U.S. DEPARTMENT OF COMMERCE
National Technical Information Service

PB-298 510

Electric Utility Steam Generating Units Background Information for Promulgated Emission Standards

(U.S.) Environmental Protection Agency, Research Triangle Park, NC

Jun 79

TECHNICAL REPORT DATA

(Please read Instructions on the reverse before completing)

1. REPORT NO.
EPA-450/3-79-021

2.

3. RECIPIENT'S ACCESSION NO.
PB298510

4. TITLE AND SUBTITLE
Electric Utility Steam Generating Units-Background
Information for Promulgated Emission Standards

5. REPORT DATE
June 1979

6. PERFORMING ORGANIZATION CODE

7. AUTHOR(S)

8. PERFORMING ORGANIZATION REPORT NO.

9. PERFORMING ORGANIZATION NAME AND ADDRESS
U. S. Environmental Protection Agency
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

10. PROGRAM ELEMENT NO.

11. CONTRACT/GRANT NO.

12. SPONSORING AGENCY NAME AND ADDRESS
DAA for Air Quality Planning and Standards
Office of Air, Noise and Radiation
U. S. Environmental Protection Agency
Research Triangle Park, North Carolina 27711

13. TYPE OF REPORT AND PERIOD COVERED

14. SPONSORING AGENCY CODE
EPA/200/04

15. SUPPLEMENTARY NOTES
Revised standards of performance for the control of particulate matter, sulfur oxides, and nitrogen oxides emissions from electric utility steam generating units were proposed on September 19, 1978. The proposed standards were supported by four separate Background Information Documents (EPA-450/2-78-005a, EPA-450/2-78-006a, EPA-450/2-78-007a, and EPA 450/2-78-007a-1.

16. Abstract

Standards of performance for the control of particulate matter, sulfur dioxide, and nitrogen oxides emissions from electric utility steam generating units have been adopted under the authority of section 111 of the Clean Air Act. These standards apply only to electric utility steam generating units capable of combusting more than 73 megawatts (250 million Btu/hr) heat input of fossil fuel and for which construction or modification began after September 18, 1978. This document contains background information, public comments, additional data collected since proposal, and EIS.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS		b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Air pollution	Particulate matter	Air Pollution Control	13B
Pollution control	Subpart Da		
Standards of performance			
Electric utility power plants			
Steam generating units			
Nitrogen oxides			
Sulfur dioxide			

18. DISTRIBUTION STATEMENT
Unlimited

19. SECURITY CLASS *(This Report)*
Unclassified

20. SECURITY CLASS *(This page)*
Unclassified

21. NO. OF PAGES
341

22. PRICE
PCA15/MF A01

EPA Form 2220-1 (9-73)

PB 298510

United States
Environmental Protection
Agency

Office of Air Quality
Planning and Standards
Research Triangle Park NC 27711

EPA-450/3-79-021
June 1979

Air

EPA

Electric Utility Steam Generating Units

EIS

Background Information for Promulgated Emission Standards

REPRODUCED BY
NATIONAL TECHNICAL
INFORMATION SERVICE
U. S. DEPARTMENT OF COMMERCE
SPRINGFIELD, VA. 22161

NSPS

EPA-450/3-79-021

Electric Utility Steam Generating Units

Background Information for Promulgated Emission Standards

Emission Standards and Engineering Division

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air, Noise, and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

June 1979

1a

This report has been reviewed by the Emission Standards and Engineering Division of the Office of Air Quality Planning and Standards, EPA, and approved for publication. Mention of trade names or commercial products is not intended to constitute endorsement or recommendation for use. Copies of this report are available through the Library Services Office (MD-35), U. S. Environmental Protection Agency, Research Triangle Park, N. C. 27711, or from National Technical Information Services, 5285 Port Royal Road, Springfield, Virginia 22161.

Publication No. EPA-450/3-79-021

Background Information
and Final
Environmental Impact Statement
for
Electric Utility Steam Generating Units

Type of Action: Administrative

Prepared by:

5/31/79
(Date)

Don R. Goodwin
Director, Emission Standards and Engineering Division
Environmental Protection Agency
Research Triangle Park, North Carolina 27711

Approved by:

5/1/79
(Date)

David G. Hawkins
Assistant Administrator for Air, Noise and Radiation
Environmental Protection Agency
401 M Street, S.W.
Washington, D. C. 20460

Final Statement Submitted to EPA's
Office of Federal Activities Review on

6/1/79
(Date)

Additional copies may be obtained at:

Environmental Protection Agency Library (MD-35)
Research Triangle Park, North Carolina 27711

This document may be reviewed at:

Central Docket Section (A-130)
Room 2903B, Waterside Mall
Environmental Protection Agency
401 M Street, S.W.
Washington, D. C. 20460

TABLE OF CONTENTS

Chapter		Page
1.	BACKGROUND	1-1
2.	SUMMARY OF PUBLIC HEARING AND COMMENTS	2-1
2.1	COMMENTERS AND PUBLIC HEARING SPEAKERS	2-1
2.2	ADMINISTRATIVE AND PROCEDURAL ACTIONS	2-61
2.3	AFFECTED FACILITY	2-64
	2.3.1 60.40a Applicability and Designation of Affected Facility	2-64
	. General Comments on Applicability	2-64
	. Combined Cycle Facilities	2-65
	. Cogeneration Facilities	2-66
	. Resource Recovery Facilities	2-68
	. Commenced Construction	2-70
	. Modification	2-72
	2.3.2 60.41a Definitions	2-74
	. Electric Utility Steam Generating Unit	2-74
	. Utility Company	2-75
	. System Capacity	2-76
	. System Emergency Reserves	2-77
	. Available System Capacity	2-78
	. Spinning Reserve	2-79
	. Emergency Condition	2-80
	2.3.3 Special Issues	2-83
	. Anthracite Coal	2-83
	. Noncontinental Areas	2-87
	. Alaskan Coal	2-88
	. Emerging Technology	2-90

TABLE OF CONTENTS
(continued)

Chapter		Page
2.4	EMISSION LIMITS	2-93
	2.4.1 60.42a Standard for Particulate Matter	2-93
	. General Comments on Particulates	2-93
	. Particulate Emission Limit	2-94
	. Best System of Emission Reduction for Particulates	2-99
	. Adequacy of the Particulate Data Base	2-106
	. Averaging Time for Particulates	2-111
	. Particulate Control in the Presence of SO_2 and/or NO_x	2-112
	. Opacity Standard for Particulates	2-113
	2.4.2 60.43a Standard for Sulfur Dioxide	2-116
	. Sulfur Dioxide Emission Limit	2-116
	. Best System of Emission Reduction for Sulfur Dioxide	2-124
	. Adequacy of the Sulfur Dioxide Data Base	2-131
	. Averaging Time for Sulfur Dioxide	2-140
	. Sulfur Removal Credit	2-143
	2.4.3 60.44a Standard for Nitrogen Oxides	2-146
	. Nitrogen Oxides Emission Limit	2-146
	. Best System of Emission Reduction for Nitrogen Oxides	2-149
	. Adequacy of the Nitrogen Oxides Data Base	2-153
	. Averaging Time for Nitrogen Oxides	2-155
	. Relationship of Nitrogen Oxides with Other Pollutants	2-156
	. Nitrogen Oxide Cost Analyses	2-157
	. Nitrogen Oxide Safety Issues	2-158

TABLE OF CONTENTS
(continued)

Chapter — Page

2.5 TESTING, MONITORING, AND REPORTING 2-159

- 2.5.1 60.46a Compliance Provisions 2-159
  - . Compliance Testing 2-159
  - . Startup, Shutdown and Emergency Bypass 2-160
- 2.5.2 60.47a Emission Monitoring 2-163
  - . General Comments on Emission Monitoring 2-163
  - . Monitoring Instrument Accuracy 2-171
  - . Monitoring Instrument Reliability 2-172
  - . Continuous Monitoring 2-174
  - . Backup Manual Monitoring 2-177
- 2.5.3 60.48a Compliance Determination Procedures and Methods 2-180
- 2.5.4 60.49a Reporting Requirements 2-183

2.6 APPENDIX A, REFERENCE METHODS 2-185

2.7 ECONOMIC IMPACTS 2-189

- . Cost to Consumer 2-189
- . Cost to Other Industries 2-197
- . Measures of Economic Impact 2-202
- . Great Lakes Transportation 2-203

2.8 ENVIRONMENTAL IMPACTS 2-204

- . General Comments on Environmental Impacts 2-204
- . Sludge 2-208
- . Acid Rain 2-210
- . Ambient Air Quality 2-211
- . Prevention of Significant Deterioration (PSD) Program 2-212

TABLE OF CONTENTS
(continued)

Chapter Page

. Water 2-214

. Other Legislation 2-215

2.9 ENERGY IMPACTS 2-217

2.10 HEALTH EFFECTS 2-220

2.11 GENERAL COMMENTS ON ENTIRE STANDARD 2-222

2.12 COMMENTS NOT ADDRESSING THE PROPOSED STANDARD 2-228

2.13 COMMENTS DUPLICATING PREVIOUS SUBMISSIONS 2-229

3. SULFUR DIOXIDE 3-1

3.1 INTRODUCTION 3-1

3.2 PERFORMANCE TEST REPORT A 3-2

3.2.1 Description of Test Sites 3-4

3.2.1.1 Conesville Unit No. 5, Columbus and Southern Ohio Electric Company 3-4

3.2.1.2 Shawnee FGD Prototypes, Tennessee Valley Authority 3-6

3.2.1.3 Mitchell No. 11, Northern Indiana Public Service Company 3-7

3.2.2 Data Gathering Systems 3-10

3.2.2.1 Conesville No. 5 Columbus and Southern Ohio Electric Company 3-10

3.2.2.2 Shawnee 10A and 10B, Tennessee Valley Authority 3-13

3.2.2.3 Mitchell No. 11, Northern Indiana Public Service Company 3-15

3.2.3 Data Reduction Procedures 3-15

3.2.4 Data Analysis 3-22

3.2.4.1 Data Calculation Assumptions 3-22

3.2.4.2 Data Availability 3-22

3.2.4.3 Statistical Analyses 3-24

3.2.5 Conclusions 3-37

TABLE OF CONTENTS
(continued)

Chapter | | Page

3.3 PERFORMANCE TEST REPORT B 3-38

3.3.1 Description of Test Sites 3-39

3.3.1.1 Shawnee FGD Prototypes, Tennessee Valley Authority 3-39

3.3.1.2 Lawrence Unit No. 4, Kansas Power and Light Company 3-41

3.3.2 Data Gathering Systems 3-43

3.3.2.1 Shawnee FGD Prototypes, Tennessee Valley Authority 3-43

3.3.2.2 Lawrence Unit No. 4, Kansas Power and Light Company 3-44

3.3.3 Data Reduction Procedures 3-46

3.3.4 Data Analysis 3-50

3.3.4.1 Data Calculation Assumptions 3-50

3.3.4.2 Data Availability 3-50

3.3.4.3 Statistical Analyses 3-52

3.3.5 Conclusions 3-59

3.4 DRY SO_2 CONTROL 3-60

3.4.1 Introduction 3-61

3.4.2 Pilot Scale Testing 3-62

3.4.3 Economics 3-66

3.4.4 Environmental and Energy Impacts 3-73

3.4.5 References 3-76

4. PARTICULATE 4-1

4.1 INTRODUCTION 4-1

4.2 LARGE BAGHOUSE CONTROL SYSTEMS 4-1

4.3 PERFORMANCE TESTING - ACID MIST 4-2

TABLE OF CONTENTS
(continued)

Chapter		Page
5.	NITROGEN OXIDES	5-1
5.1	INTRODUCTION	5-1
5.2	INFORMATION RECEIVED AFTER PROPOSAL	5-1
6.	ENVIRONMENTAL IMPACT STATEMENT SUMMARY	6-1
6.1	INTRODUCTION	6-1
6.2	PUBLIC COMMENTS	6-2
6.3	ENVIRONMENTAL IMPACTS	6-2
6.4	SUMMARY OF IMPACTS FOR FINAL ALTERNATIVES CONSIDERED	6-4

1. BACKGROUND

In December 1971, under section 111 of the Clean Air Act, EPA promulgated standards of performance to limit emissions of SO_2, particulate matter, and NO_x from new, modified, and reconstructed fossil-fuel-fired steam generators (40 CFR 60.40 et seq.). Since that time, the technology for controlling emissions from this source category has improved, but emissions of SO_2, particulate matter, and NO_x continue to be a national problem. In 1976, steam electric generating units contributed 24 percent of the particulate matter, 65 percent of the SO_2, and 29 percent of the NO_x emissions on a national basis.

EPA was petitioned on August 6, 1976, by the Sierra Club and the Oljato and Red Mesa Chapters of the Navaho Tribe to revise the SO_2 standard so as to require a 90 percent reduction in SO_2 emissions from all new coal-fired power plants. The petition claimed that advances in technology since 1971 justified a revision of the standard. As a result of the petition, EPA agreed to investigate the matter thoroughly. On January 27, 1977 (42 FR 5121), EPA announced that it had initiated a study to review the technological, economic, and other factors needed to determine to what extent the SO_2 standard for fossil-fuel-fired steam generators should be revised.

On August 7, 1977, President Carter signed into law the Clean Air Act Amendments of 1977. The provisions under section 111(b)(6) of the Act, as amended, required EPA to revise the standards of performance for fossil-fuel-fired electric utility steam generators within 1 year after enactment.

After the Sierra Club petition of August 1976, EPA initiated studies to review the advancement made on pollution control systems at power plants. These studies were continued following the amendment of the Clean Air Act. In order to meet the schedule established by the Act, a preliminary assessment of the ongoing studies was made in late 1977. A National Air Pollution Control Techniques Advisory Committee meeting was held on December 13 and 14, 1977, to present EPA preliminary data. The meeting was open to the public and comments were solicited.

The Clean Air Act Amendments of 1977 required the standards to be revised by August 7, 1978. When it appeared that EPA would not meet this schedule, the Sierra Club filed a complaint on July 14, 1978, with the U. S. District Court for the District of Columbia requesting injunctive relief to require, among other things, that EPA propose the revised standards by August 7, 1978. A consent order was developed and issued by the court requiring the EPA Administrator to (1) deliver the proposal package to the office of the FEDERAL REGISTER by September 12, 1978, and (2) promulgate the final standards within 6 months after proposal (i.e., by March 19, 1979).

The Administrator delivered the proposal package to the office of the FEDERAL REGISTER by September 12, 1978, and the proposed regulations were published September 19, 1978 (43 FR 42154). Following the proposal EPA initiated additional testing to assist in resolving a number of technical issues raised during the proposal. EPA also contacted other sources of information to assist in resolution of these issues. Following proposal EPA also initiated additional computer analyses of the impact of various alternative standards.

Public comments on the proposal were requested by December 15, and a public hearing was held December 12 and 13, the record of which was held open until January 15, 1979. More than 700 comment letters were received on the proposal. The comments were carefully considerd, however the issues could not be sufficiently evaluated in time to promulgate the standards by March 19, 1979. On that date EPA requested of the Court, and was granted, an extension whereby the Administrator would sign and deliver the final standards to the FEDERAL REGISTER for publication on or before June 1, 1979.

This document represents a summary of the comments received, technical data collected since proposal, and an EIS summary which contains a cross-reference to other documentation used in development of the final standards.

2.0 SUMMARY OF PUBLIC HEARING AND COMMENTS

2.1 Commenters and Public Hearing Speakers

Table 2-I presents a listing of persons submitting written comment on the proposed standard. Also shown is the EPA docket number assigned to each comment and the organizational affiliation of each commenter. Table 2-II presents a listing of persons who presented testimony at the public hearing and Table 2-III presents a listing of official written comments from other federal organizations. Both of these listings also show the assigned EPA docket numbers.

TABLE 2-I

LIST OF PERSONS SUBMITTING WRITTEN COMMENTS

No.	Docket No.	Commenters
1	D-1	H. S. King (U. S. Resident)
2	D-2	J. W. Kellog (U. S. Resident)
3	D-3	Alvin P. Fenton (U. S. Resident)
4	D-4	Mrs. Norman Jackson (U. S. Resident)
5	D-5	Paul C. Williams (U. S. Resident)
6	D-6	Alice C. Grant (U. S. Resident)
7	D-7	Mr. and Mrs. Kenneth Bell (U. S. Resident)
8	D-8	Ray A. Arditi (U. S. Resident)
9	D-9	Verlyn Marth (U. S. Resident)
10	D-10	Vallerie J. Prime (Citizens United for Responsible Energy)
11	D-14	Bernard L. Coffindaffer (Craigsville Distributing Co., Inc.)
12	D-15	Richard Rao (Research-Cottrell, Inc.)
13	D-21	H. John Heinz III, U.S.S. (U. S. Senate)

TABLE 2-I (Continued)

No.	Docket No.	Commenters
14	D-22	Roger D. Freriks (U. S. Resident)
15	D-27	Charles L. Sibley (U. S. Resident)
16	D-28	Frederick Benedikt (U. S. Resident)
17	D-29	William T. Ossmer (Clay Citizens Coalition)
18	D-30	Glenn W. Ditsworth (U. S. Resident)
19	D-31	Earl R. Benson (U. S. Resident)
20	D-32	John M. Wade (U. S. Resident)
21	D-33	D. Lane Berrier, Jerry W. Via (V.P.I. and S.U., Department of Biology)
22	D-34	Mr. and Mrs. G. J. Jenkins Mary Fielder L. C. Fullerd B. Prasswell Patty Kug Jill Kay Bobby Frith Edna Crapps Mary Bolgla Kenny Stanley (U. S. Residents)
23	D-38	Robert L. Sandvig (U. S. Resident)
24	D-39	Bob Packwood (U. S. Senate)
25	D-40	Robert N. Cleveland (Buckeye Power Inc.)

TABLE 2-I (Continued)

No.	Docket No.	Commenters
26	D-41	S. A. Shorter (U.S. Resident)
27a	D-42	Phillip G. Sikes (U.S. Resident)
27b	D-43	Dick Clark (U.S. Senate) and John M. Hardie (Iowa Public Service Company)
28	D-44	Helen R. Hartley (U. S. Resident)
29	D-45	Evelyn E. Wardle (U. S. Resident)
30	D-46	Don Schrader (U. S. Resident)
31	D-48	Charles David Parent (U. S. Resident)
32	D-49	Kenneth Snolinsky (U. S. Resident)
33	D-50	Gary N. Weinreich (American Natural Service Co.)
34	D-52	Thomas A. Parkhill (U. S. Resident)
35	D-53	Ron Tober (U. S. Resident)
36a	D-55	Mrs. Jean Kronman (U.S. Resident)
36b	D-57	Patrick Ragosta (U.S. Resident)
37	D-58	Edward L. Sears (U.S. Resident)

TABLE 2-I (Continued)

No.	Docket No.	Commenters
38	D-59	Robert West (University of Virginia, Department of Chemistry)
39	D-60	Barbara Hudgins (U.S. Resident)
40	D-61	Marvin Bing (U.S. Resident)
41	D-62	Phillip G. Sikes (U.S. Resident)
42	D-63	Andrea Wightman Mike Moles (U.S. Residents)
43a	D-64	Ken Norstrom (U.S. Resident)
43b	D-65	Ruth C. Clusen (Department of Energy)
44	D-67	Paul R. Hanson (Douglas County Development Association, Inc.)
45	D-68	Connie Okman (U. S. Resident)
46	D-69	Catherine Alexander (U. S. Resident)
47	D-70	Lois Binkley (U. S. Resident)
48	D-71	Laurie Wolfe (U. S. Resident)
49	D-72	Frank Griffith (Iowa Public Service Co.)
50	D-73	Theodore S. May (U.S. Resident)
51	D-74	Clarence Petty (U.S. Resident)

TABLE 2-I (Continued)

No.	Docket No.	Commenters
52	D-75	Alvin Blyer (U.S. Resident
53	D-76	John L. Jordan (U.S. Resident)
54	D-77	George Popper (U.S. Resident)
55	D-78	C. David Gorton (U.S. Resident)
56	D-79	Jean Hough (U. S. Resident)
57	D-80	Ernest P. Kline (Lt. Governor of Pennsylvania)
58	D-82	Greg H. Thompson (U. S. Resident)
59	D-83	Tom Paul (U. S. Resident)
60	D-84	Marla Dawn Music (U. S. Resident)
61	D-85	Ken Long (U. S. Resident)
62	D-86	Thane Puissegar (U. S. Resident)
63	D-87	John J. LaFalce (U. S. House of Representatives)
64	D-88	John J. LaFalce John Buchanan Tom Bevill Robert E. Bodham Guinn McKay Walter Flowers G. V. (Sonny) Montgomery Henry J. Nowak Stanley N. Lundine (U. S. House of Representatives)

TABLE 2-I (Continued)

No.	Docket No.	Commenters
65	D-90	Francis E. Drake, Jr. (Rochester Gas and Electric Corp.)
66	D-91	Russell Toal (U. S. Resident)
67	D-92	Theodore F. Gies (U. S. Resident)
68	D-93	James F. Todd, Jr. (U. S. Resident)
69	D-94	Eleanore C. Robbins (U. S. Resident)
70	D-95	R. Lyman Wood (U. S. Resident)
71	D-96	Rural Route 1 (Gentryville, Indiana)
72	D-97	Frank E. Doherty (U. S. Resident)
73	D-98	Ron Guenther (U. S. Resident)
74	D-99	Harold I. McNally (U. S. Resident)
75	D-100	Dorothy R. Munn (U. S. Resident)
76	D-101	Kirk Capper (U. S. Resident)
77	D-102	T. A. Hendrickson (U. S. Resident)
78	D-103	David Donnenfield (U. S. Resident)
79	D-104	Charles F. Walter, M.D. (U. S. Resident)
80	D-105	William E. Doughty, M.D. (U. S. Resident)

TABLE 2-I (Continued)

No.	Docket No.	Commenters
81	D-106	Mary B. Daniels (Tri-County Ranchers Assn.)
82	D-107	Chuck Botsko (U.S. Resident)
83	D-108	Alan Nessman (U. S. Resident)
84	D-109	Katy Kimball (U. S. Resident)
85	D-110	Nancy L. McBride (U. S. Resident)
86	D-111	Dr. Jill C. Mannisto (U. S. Resident)
87	D-112	Rossella Johanson (U. S. Resident)
88	D-113	I. W. Tucker (National Environmental Balance, Inc.)
89	D-114	Robert Mendelsohn (University of Washington, Department of Economics)
90	D-115	Emmett J. Ferretti, P.E. (U. S. Resident)
91	D-116	Warren Little (U. S. Resident)
92	D-117	Gordon "Dass" Adams (U. S. Resident)
93	D-118	Robert Oset (U. S. Resident)
94	D-119	Donald Tobkin (U. S. Resident)
95	D-120	Brandt Mannchen (U. S. Resident)
96	D-121	Rev. Daniel Crosby (St. Labre Indian School)

TABLE 2-I (Continued)

No.	Docket No.	Commenters
97	D-122	Mark M. McClellan (Citizens Advisory Council, Pa.)
98	D-123	C. Michael Reimringer (U. S. Resident)
99	D-124	Wells Eddlerman (U. S. Resident)
100	D-125	Rachel Matteson (U. S. Resident)
101	D-126	Sherry Cummings (U. S. Resident)
102	D-127	Julia Corliss (U. S. Resident)
103	D-128	Ulysses A. Carlini (KNOP-TV)
104	D-129	Ann A. Welch (U. S. Resident)
105	D-130	Brandt Mannchen (Sierra Club)
106	D-131	Elanne Nusich (U. S. Resident)
107	D-132	A. Franklin Brayman, III, P.E. (U. S. Resident)
108	D-133	Jill Ann Baxter (U. S. Resident)
109	D-134	Maurice Pedriani (Northwest Ministry of Lehigh Presbytery)
110	D-135	Toby Berg (U. S. Resident)
111	D-136	Brian J. Davey (U. S. Resident)
112	D-137	Ernest G. Panciera (U. S. Resident)

TABLE 2-I (Continued)

No.	Docket No.	Commenters
113	D-138	Ruth Sjarelmeyer, M.D. (U. S. Resident)
114	D-139	Mr. and Mrs. Al Razor (U. S. Resident)
115	D-140	Dr. and Mrs. Theodore J. Voneida (U. S. Resident)
116	D-141	Hazel H. Thompson (U. S. Resident)
117	D-142	Robert H. Lyon (U. S. Resident)
118	D-143	Betsy Kalbert (U. S. Resident)
119	D-144	Marlene Raynor (U. S. Resident)
120	D-145	D. E. Heyburn (Babcock & Wilcox)
121	D-146	Donald Forman (U. S. Resident)
122	D-147	J. D. Hicks (Tampa Electric Co.)
123	D-148	W. M. Anderson (U. S. Resident)
124	D-149	Dorothy Eoyrs (U. S. Resident)
125	D-150	R. L. Hufman (Golden Valley Electric Assoc., Inc.)
126	D-151	George Gryc (U. S. Resident)
127	D-152	Harvey Bieber (McCone Agricultural Protection Organization)

TABLE 2-I (Continued)

No.	Docket No.	Commenters
128	D-153	Robert A. Bibb, P.E. (Lutz, Daily & Brain)
129	D-154	Michael W. Hiller, M.D. (U. S. Resident)
130	D-155	W. Bing (U. S. Resident)
131	D-156	A. Arenal (Southern California Edison Company)
132	D-157	Hester McNulty (League of Women Voters)
133	D-158	Wilbur White Mary White Mac White (U. S. Residents)
134	D-159	Peter C. Lewis (Hawaiian Electric Co., Inc.)
135	D-160	Robert C. Batson (U. S. Resident)
136	D-161	Madeline S. Yale (U. S. Resident)
137	D-162	Thomas J. Hogarty, M.D. (U. S. Resident)
138	D-163	Bruno C. Boik (AMAX Engineering and Management Services Co.)
139	D-164	Charlotte Hers... (U. S. Resident)
140	D-165	Julia Mann (U. S. Resident)
141	D-166	Gerald A. Jayne (U. S. Resident)

TABLE 2-I (Continued)

No.	Docket	Commenters
142	D-167	John M. Hardie (Iowa Public Service Company)
143	D-168	S. B. Hager (Duke Power Company)
144	D-169	Jane Sharp (Conservation Council of N.C.)
145	D-170	George Smith (U. S. Resident)
146	D-171	Danny Buck (U. S. Resident)
147	D-172	Mary Troland (U. S. Resident)
148	D-173	John G. White, Jr. (U. S. Resident)
149	D-174	David P. Cook (American Lung Association)
150	D-175	Robert R. Wahler (WAHLCO)
151	D-176	Robert K. Turner (U. S. Resident)
152	D-177	Dr. Anne Harbough (U. S. Resident)
153	D-178	Christopher Tesar (Coalition for Canyon Preservation)
154	D-179	Herbert Deich (MDH Industries, Inc.)
155a	D-180	Anne H. Garde (U. S. Resident)
155b	D-181	George Smith (Duplicate of D-170)
156	D-182	Kim DePrenger (U. S. Resident)

TABLE 2-I (Continued)

No.	Docket No.	Commenters
157	D-183	Glenn Walter (U. S. Resident)
158	D-184	David H. Hickcox (U. S. Resident)
159	D-185	Eleanor L. Buchanan (U. S. Resident)
160	D-186	Mrs. Ken Christian (U. S. Resident)
161	D-187	Thomas Geary (U. S. Resident)
162	D-188	Marian Gerrish (U. S. Resident)
163	D-189	Deleted
164	D-190	Karen Zackheim (U. S. Resident)
165	D-191	Alexander McAfee (Cleveland-Cliffs Iron Co.)
166	D-192	Cynthia Jerriel (U. S. Resident)
167	D-193	Marvin Cole, M.D. (U. S. Resident)
168	D-194	Esther K. Epling (U. S. Resident)
169	D-195	Barbara Eliversey (U. S. Resident)
170	D-196	John & Hope Kruse (U. S. Residents)
171	D-197	C. Ballsun (U. S. Resident)

TABLE 2-I (Continued)

No.	Docket No.	Commenters
172	D-198	Elizabeth P. Elliston (Sandoval Environmental Action Community)
173	D-199	Daniel Shubert, M.D. (U. S. Resident)
174	D-200	Margaret Lopsen (U. S. Resident)
175	D-201	Carol Harlow (U. S. Resident)
176	D-202	Edward J. Healy (U. S. Resident)
177	D-203	Herman A. Fritschen (Cities Service Company)
178	D-204	K. M. Wilson, P.E. (Coal Tech)
179	D-205	Robert V. Tanner (Santee Cooper, South Carolina Public Service Authority)
180	D-206	Gerald McGowan (Lear Siegler, Inc.)
181	D-207	Richard F. Straub (U. S. Resident)
182	D-208	Clifford Bove (U. S. Resident)
183	D-209	Mr. and Mrs. Stuart A. More (U. S. Residents)
184	D-210	J. R. Endicott (Board of Public Utilities, City of Coldwater, Mont.)
185	D-211	John R. Bartlit (New Mexico Citizens for Clean Air & Water, Inc.

TABLE 2-I (Continued)

No.	Docket No.	Commenters
186	D-212	Alfred T. Whatley, Ph.D. (Air Pollution Control Commission, Colorado Department of Health)
187	D-213	Hugh Zackheim (Montana Wildlife Federation)
188	D-214	Sandra Gajkowski (American Steamship Company)
189	D-215	W. G. Crosby (South Carolina Department of Health and Environmental Control)
190	D-216	C. M. Heidel (Detroit Edison)
191	D-217	Bruce Beyrest (Chevron U.S.A., Inc.)
192	D-218	John M. Daniel, Jr., P.E. (Commonwealth of Virginia, State Air Pollution Control Board)
193	D-219	Carlton Rush (The Cleveland Electric Illuminating Company)
194	D-220	Stephen J. Knapp (U. S. Resident)
195	D-221	Mr. and Mrs. Art Hayes, Jr. (U. S. Residents)
196	D-222	Nora Hope (U. S. Resident)
197	D-223	F. W. Lewis (Middle South Services, Inc.)
198	D-224	N. R. Lee (Gulf States Utilities Company)
199	D-225	Harry L. Blomquist, Jr. (Coastal States Gas Corporation)

TABLE 2-I (Continued)

No.	Docket No.	Commenters
200	D-226	Katherine Spers (U. S. Resident)
201	D-227	James B. Edwards, Governor (State of South Carolina)
202	D-228	Michael Wustine (U. S. Resident)
203	D-229	Betty Woodruff (League of Woman Voters of Missouri)
204	D-230	Dr. Michael D. Williams (New Mexico Citizens for Clean Air and Water)
205	D-231	John L. Wood (Control and South West Services)
206	D-232	Frank Linder (Dairyland Power Cooperative)
207	D-233	W. H. Krome George (Aluminum Company of America)
208	D-234	S. J. Sweeney (Boston Edison Company)
209	D-235	Tom Kenny (U. S. Resident)
210	D-236	Robert Potter (U. S. Resident)
211	D-237	Samuel J. Tuthill (Iowa Electric Light and Power Company)
212	D-238	James F. Coerver (Louisianna Air Control Commission)
213	D-239	Craig M. Weaver (U. S. Resident)

TABLE 2-I (Continued)

No.	Docket No.	Commenters
214	D-240	C. M. Woodstock (U. S. Resident)
215	D-241	Richard Hopkins (U. S. Resident)
216	D-242	P. F. Gorman (Chas. T. Main, Inc.)
217	D-243	Frank C. Perunko (U. S. Resident)
218	D-244	David D. Drake (Dept. of Energy, Frankfort, Kentucky)
219	D-245	Frank Clements (United Mine Workers of America)
220	D-246	Keven Greene (Citizens for a Better Environment)
221	D-247	Sidney R. Orem (Industrial Gas Cleaning Institute, Inc.)
222	D-248	Richard A. Weber, D.D.S. (U. S. Resident)
223	D-249	Russel V. Randle (Yale Law School)
224	D-250	M. L. Hurstell (New Orleans Public Service Co.)
225	D-251	W. W. Kroeber (Montana-Dakota Utilities Co.)
226	D-252	Virgil E. Peterson (Hassier Energy)
227	D-253	E. E. Hall (Pacific Gas and Electric Company)

TABLE 2-I (Continued)

No.	Docket No.	Commenters
228	D-254	W. T. Slick, Jr. (Exxon Company, U.S.A.)
229	D-255	S. B. Milligan (The Rust Engineering Company)
230	D-256	R. C. Kuether (Kansas Power and Light Company)
231	D-257	Joseph A. Schulz (The Pittston Company Coal Group)
232	D-258	Dennis R. Nelson (U. S. Resident)
233	D-259	Gene H. Gockley (Pennsylvania Power & Light Co.)
234	D-260	Don Gasper (W. Va. Dept. of Natural Resources)
235	D-261	John A. Scarola (EBASCO Services Incorporated)
236	D-262	H. E. Bond (Atlantic Richfield Company)
237	D-263	J. D. Phillips (City of Colorado Springs)
238	D-264	Ed Malenovsky (U. S. Resident)
239	D-265	Steve Berg-Hansen (Rocky Mountain Energy Company)
240	D-266	Claude M. Soales, III (Orange and Rockland Utilities, Inc.)
241	D-267	John J. Dyson (Department of Commerce, State of New York)

TABLE 2-I (Continued)

No.	Docket No.	Commenters
242	D-268	Thomas C. Austin (Air Resources Board, State of California)
243	D-269	Noel and Irene Rosetta (U. S. Residents)
244	D-270	Christopher S. Bond Charles A. Blackmar (U. S. Residents)
245	D-271	Edward G. Weber (Southwestern Public Service)
246	D-272	R. E. Parnelle (Florida Power Corporation)
247	D-273	Walter G. Saunders. M.D., F.A.C.O.G. (U. S. Resident)
248	D-274	T. V. Lennick (Cooperative Power Association)
249	D-275	R. Bruce Campbell (U. S. Resident)
250	D-276	James Fish (Great Lakes Commission)
251	D-277	W. H. Axtman (American Boiler Manufacturer Association)
252	D-278	Andy P. Bartson (U. S. Resident)
253	D-279	John R. Hopkins (U. S. Resident)

TABLE 2-I (Continued)

No.	Docket No.	Commenters
254	D-280	Gary L. Allison (Wheelabrator Cleanfuel Corporation)
255	D-281	Mr. and Mrs. J. Lewis (U.S. Resident)
256	D-282	Cal Wilson (U.S. Resident)
257	D-283	F. W. Giaaccone (EPA, Air Facilities Branch)
258	D-284	Ted Schwinder, Acting Governor (State of Montana)
259	D-285	Ann C. Rick (League of Women Voters of West Va., Inc.)
260	D-286	John M. Daniel, Jr., P.E. (State Air Pollution Control Board, Virginia)
261	D-287	A. E. Pearson (Nevada Power Company)
262	D-288	Fred A. Shiosaki (The Washington Power Company)
263	D-289	Lloyd McCaskey (Oakdale Electric Cooperative)
264	D-290	Robert C. Weaver (National Association of Counties)
265	D-291	Henry Peck (U.S. Resident)
266	D-292	Steve Rice (U.S. Resident)
267	D-293	James H. Hughes (U.S. Resident)
268	D-294	Richard Adler (Clark Electric Cooperative)

TABLE 2-I (Continued)

No.	Docket No.	Commenters
269	D-295	Helen R. Hartley (U.S. Resident)
270	D-296	Steven Doelder (U.S. Resident)
271	D-297	Victor N. Peterson (Pierce-Pepin Electric Cooperative)
272	D-298	Mr. Philip Parker (Polk-Barnett Electric Cooperative)
273	D-299	Virgil M. Dufeck (Eau Claire Electric Cooperative)
274	D-300	Virgil C. Summer (South Carolina Electric and Gas Company)
275	D-301	W. H. Axtman (American Boiler Manufacturers Association)
276	D-302	Spencer P. Felt (The National Filter Media Corporation)
277	D-303	Thomas A. Parkhill (U.S. Resident)
278	D-304	J. D. Selby (Consumers Power Company)
279	D-305	William L. Perdue (The Kansas Power and Light Company)
280	D-306	Jerrold L. Jacobs (Atlantic Electric)
281	D-307	William F. Symons (Atlantic Electric)
282	D-308	W. G. Kuhns (General Public Utilities Corp.)

TABLE 2-I (Continued)

No.	Docket No.	Commenters
283	D-309	V. J. Daniel, Jr. (Mississippi Power Company) and Trent Lott (U.S. House of Representatives)
284a	D-310	V. J. Daniel, Jr. (Mississippi Power Company) and Gillespie V. Montgomery (U.S. House of Representatives)
284b	D-311	Stuart E. Eizenstaat (Assistant to the President, The White House)
284c	D-312	Stuart E. Eizenstaat (Assistant to the President, The White House)
285	D-313	J. A. Stuart (South Coast Air Quality Mgmnt. District)
286	D-314	L. E. Zeni (Department of Natural Resources, State of Maryland)
287	D-315	A. E. Kintigh (New York State Electric and Gas Corporation)
288	D-316	Richard Dorgan (U.S. Resident)
289	D-317	John M. Arthur (Duquesne Light Company)
290	D-318	E. J. Evans (U. S. Resident)
291	D-319	Earl L. Johnson (Tri-County Electric Cooperative)
292	D-320	Roger A. Hofacker (Western Systems Coordinating Council)
293	D-321	Wayne R. Johnson (Kansas City Power and Light Company)

TABLE 2-I (Continued)

No.	Docket No.	Commenters
294	D-322	F. K. Smith (Texas Municipal Power Agency)
295	D-323	Carolyn Embry (U.S. Resident)
296	D-324	Jim Jontz (House of Representatives State of Indiana)
297	D-325	Robert H. Short (Portland General Electric Co.)
298	D-326	Robert J. Reichelderfer (First Presbyterian Church)
299	D-327	James Conroy (U.S. Resident)
300	D-328	Keith Guelff (U.S. Resident)
301	D-329	Jacob T. Lee (Dunn County Electric Cooperative)
302	D-330	D. L. Renberger (Washington Public Power Supply System)
303	D-331	Lois J. Imhoff (The League of Women Voters of Arkansas)
304	D-332	John J. LaFalce (U.S. House of Representatives)
305	D-333	Herman E. Talmadge (U.S. Senate)
306	D-334	Ray Roberts Sam B. Hall Omar Burleson Ahrahani Kazen William Mattox W. R. Poage Charles Wilson Tale Malford J. Hightower Ali E. Teague Henry B. Gonzales J. J. Pickle Bob Krueger George Mahon (U.S. House of Representatives)

TABLE 2-I (Continued)

No.	Docket No.	Commenters
307	D-335	Frank W. Griffith (Iowa Public Service Company)
308	D-336	W. Henson Moore (U.S. House of Representatives)
309	D-337	Janice L. Whitten, M.C. (U.S. House of Representatives)
310	D-338	Dan Daniel (U.S. House of Representatives)
311	D-339	Norman E. D'Amours (U.S. House of Representatives) and Russell A. Holden (New England Power Company)
312	D-340	Charles H. Percy (U.S. Senate) and Kenneth L. Andres (Central Illinois Public Service Co.)
313	D-341	Allyn M. Davis (U.S. EPA, Air and Hazardous Materials Division)
314	D-342	Mrs. Magdelene S. Atkinson (U.S. Resident)
315	D-343	W. G. Kuhns (General Public Utilities Corp.) and William A. Verrochi (Pennsylvania Electric Company)
316	D-344	Charles E. Grassley (U.S. House of Representatives)
317	D-345	Francis E. Drake, Jr. (Rochester Gas and Electric Corp.)
318	D-346	Norman A. Johnson, Jr. (Mississippi Public Service Commission)
319	D-347	A. Frank Brayman III, P.E. (U.S. Resident)

TABLE 2-I (Continued)

No.	Docket No.	Commenters
320	D-348	M. Caldwell Butler (U.S. House of Representatives)
321	D-349	R. L. Hufman (Golden Valley Electric Assn., Inc.)
322	D-350	Hubert B. Erwin (California Lung Association)
323	D-351	Loren L. Roberts (Long Beach Lung Association)
324	D-352	Harry W. Read Beverly A. Bermacher (U.S. Residents)
325	D-353	Marlene and Gaylord Yost (U.S. Resident)
326	D-354	Larry Schultz (The Izaak Walton League of America, Inc.)
327	D-355	Bernard P. Wolff, M.D. (Georgia Lung Association)
328	D-356	Richard Hopkins (U.S. Resident)
329	D-357	Cecile Helsel (City of Superior, Wisconsin)
330	D-358	Lewis C. Green (Green, Henning & Henry)
331	D-359	Howard E. Hesketh, P.E. (U.S. Resident)
332	D-360	Ben Chaiken (Arizona Lung Association)
333	D-361	Earl L. King (Allied Power Cooperative of Iowa)
334	D-362	Mrs. Jean Ingold (U.S. Resident)
335	D-363	Walter Dickinson, Jr. (American Lung Association)

TABLE 2-I (Continued)

No.	Docket No.	Commenters
336	D-364	Walter L. Zadan (Group Against Smog and Pollution)
337	D-365	Mr. Burnet D. Brown (U.S. Resident)
338	D-366	Ernst W. Mueller (Dept. of Environmental Conservation, State of Alaska)
339	D-367	Robert A. Arnatt, Ph.D (Dept. of Natural Resources, State of Wisconsin)
340	D-368	J. L. Lombardo (Island Creek Coal Company)
341	D-369	S. D. Goodman (Gilbert Associates, Inc.)
342	D-370	Karl H. Schafer (Iowa-Illinois Gas and Electric Co.)
343	D-371	James C. Wilson (Rocky Mountain Energy Company)
344	D-372	Hazel Odegard (U.S. Resident)
345	D-373	James L. Grahl (Basin Electric Power Corporation)
346	D-374	Tom Quinn (Governor's Office, State of Calif.)
347	D-375	Ron Crouch (Sierra Club, Cumberland Chapter)
348	D-376	Rev. Carleton Schaller, Jr. (U.S. Resident)
349	D-377	Bernard Perry (U.S. Resident)
350	D-378	Anthony L. Van Geet, Ph.D. (U.S. Resident)

TABLE 2-I (Continued)

No.	Docket No.	Commenters
351	D-379	Kathleen Hultgren (U.S. Resident)
352	D-380	W. Donham Crawford (Gulf States Utilities Company)
353	D-381	Marshall C. Deason, Jr. (American Lung Association of Southeast Florida, Inc.)
354	D-382	V. J. Holmes (U.S. Resident)
355	D-383	Glenn Morazzine (U.S. Resident)
356	D-384	Glen A. Ramsdell, M.D. (American Lung Assn. of Indiana)
357	D-385	Ruth M. Young (U.S. Resident)
358	D-386	Irving Mushlin (Dade-Monroe Lung Association, Inc.)
359	D-387	Powell Foster (U.S. Resident)
360	D-388	Charles Schultze Barry Bosworth (Lung Association of San Diego and Imperial Counties)
361	D-389	James T. Allison (Mid-Memphis Improvement Assn.)
362	D-390	Elaine Walker, R.R.T. (American Lung Association)
363	D-391	Priscilla G. Robinson (Southwest Environmental Service)
364	D-392	Fay Witz (City of Highland Park, Illinois)
365	D-393	Norman O. Stein, Ph.D. (American Lung Association)

TABLE 2-I (Continued)

No.	Docket No.	Commenters
366	D-394	Beryl Reichenberg (Clean Air Coalition)
367	D-395	John and Marilyn Layon (U.S. Resident)
368	D-396	John C. Bhend (U.S. Resident)
369	D-397	D. T. Berube (The Montana Power Company)
370	D-398	Donald Samsen (St. Croix County Electric Cooperative)
371	D-399	Don E. Gerard (Board of Public Utilities, McPherson, Kansas)
372	D-400	Lawrence L. Roeser (Arizonans for Jobs and Energy)
373	D-401	John J. Bergan (Colorado-Ute Electric Assn., Inc.)
374	D-402	William F. Matson (Allegheny Electric Cooperative, Inc.)
375	D-403	Gerald G. Bachman (Mid-Continent Area Power Pool)
376	D-404	D. D. Jordon (Houston Lighting and Power Company)
377	D-405	William W. Llyons (Northern Energy Resources Company)
378	D-406	James A. Patton (Northern Plains Resource Council)
379	D-407	Eric N. Sloth, Ph.D. (Nebraska Public Power District)
380	D-408	Irvin D. Parker (Dept. of Consumer Affairs, State of South Carolina)

TABLE 2-I (Continued)

No.	Docket No.	Commenters
381	D-409	J. R. Thorpe (GPU Service Corporation)
382	D-410	John W. Ellis (Puget Sound Power and Light Co.)
383	D-411	Priscilla Maclean (League of Women Voters of Montana)
384	D-412	G. P. Reidy (The CAM Company)
385	D-413	S. David Freeman (Tennessee Valley Authority)
386	D-414	Donald C. Lutken (Mississippi Power and Light Company)
387	D-415	W. M. Taylor (Texas Electric Service Company)
388	D-416	Alan Beals (National League of Cities)
389	D-417	D. R. Betterton (Houston Lighting and Power)
390	D-418	Dr. T.A. Vanderslice (General Electric Company)
391	D-419	Economic Development Council of Northeastern Pennsylvania
392	D-420	H. John Heinz III, U.S.S. (United States Senate)
393	D-421	Glenn G.C. Olson (Northern States Power Company)
394	D-422	Clarence R. Feldman (Americans for Energy Independence)
395	D-423	Jay D. Myster (Otter Tail Power Company)
396	D-424	Abe H. Frumkin (representing the Anthracite Development and Utilization Association)

TABLE 2-I (Continued)

No.	Docket No.	Commenters
397	D-425	John R. McNamara (WEST Associates)
398	D-426	Arthur D. Rheingold (American Electric Power Service Co.)
399	D-427	Kent Briggs (behalf of Scott M. Matheson, Governor of Utah)
400	D-428	Mr. and Mrs. Gordon Waller (U.S. Residents)
401	D-429	S.B. Jacobs (Stone and Webster Engineering Corporation)
402	D-430	Leroy Michael, Jr. (Salt River Project)
403	D-431	John A. Scarola (Ebasco Services Incorporated)
404	D-432	Patty Kluver (U.S. Resident)
405	D-433	Gerald G. Bachman (Nebraska Power Industry Committee)
406	D-434	Wallace D. McRae (Rosebud Protective Association)
407	D-435	A.E. Michon (Burlington Northern)
408	D-436	Arthur F. Armstrong (Contraves Goerz Corporation)
409	D-437	C. E. Watson (Dallas Power and Light Company)
410	D-438	James H. Anthony (Intermountain Power Project)
411	D-439	Delaware Valley Citizen's Council for Clean Air

TABLE 2-I (Continued)

No.	Docket No.	Commenters
412	D-440	A. L. Cahn (Bechtel Power Corporation)
413	D-441	Jerilyn E. Bieher (McCone Women Involved in Farm Economics)
414	D-442	Richard J. Grant (Central Illinois Public Service Co.)
415	D-443	L. A. McReynolds (Phillips Petroleum Company)
416	D-444	James K. Hambright (Bureau of Air Quality Control, Pennsylvania)
417	D-445	Keith Molin (Dept. of Commerce, Michigan)
418	D-446	Curtis L. Ritland (Iowa Power)
419	D-447	A.O. Courtney (Commonwealth Edison)
420	D-448	James L. Mulloy (Department of Water and Power, City of Los Angeles)
421	D-449	Joseph E. Fulton (City Public Service Board of San Antonio, Texas)
422	D-450	H.E. Bond (Atlantic Richfield Company)
423	D-451	James F. Purcell (Northern Indiana Public Service Co.)
424	D-452	James N. Howell (Great Lakes Steel Div. of National Steel Corporation)
425	D-453	Russell V. Randle (Yale Environmental Law School)
426	D-454	Matthew Gould (National Assn. of Manufacturers)

TABLE 2-I (Continued)

No.	Docket No.	Commenters
427	D-455	Richard D. McRanie (Southern Company Services)
428	D-456	Dean B. Suagee (U.S. Resident)
429	D-457	James Barrett (Michigan State Chamber of Commerce)
430	D-458	Peter H. Benziger (Potomac Electric Power Company)
431	D-459	Mary Ellen Schraeder (Department of Public Property, Springfield, Illinois)
432	D-460	Walter T. Woelfle (Wisconsin Electric Power Company)
433	D-461	Andrew T. Bahn, P.E. (Illinois Power Company)
434	D-462	Paul H. Arbesman (Department of Environmental Protection, New Jersey)
435	D-463	Joe L. Gremban (Sierra Pacific Power Company)
436	D-464	Robert A. McKnight (Indianapolis Power and Light Company)
437	D-465	David M. Anderson (Bethlehem Steel Corporation)
438	D-466	S.F. Sherwood (El Paso Coal Company)
439	D-467	Paul C. Hittle (Consumers Power Company)

TABLE 2-I (Continued)

No.	Docket No.	Commenters
440	D-468	Victoria Potter (State of Wisconsin)
441	D-469	Paul Ember, Jr. Richard C. Clancy (Utility Solid Waste Activities Group)
442	D-470	Louis R. Paley (U.S. EPA)
443	D-471	Morris L. Brehmer, Ph.D. (Vepco)
444	D-472	Jarrell E. Southall (Department of Pollution Control and Ecology, State of Arkansas)
445	D-473	William L. Keepers (Wisconsin Power and Light Company)
446	D-474	Edward Berlin and Andrew D. Weissman representing Appalachian Power Company, Boston Edison Company, Commonwealth Edison Company, Consolidated Edison Company of New York, Inc., Florida Power and Light Company, Indiana and Michigan Electric Company, Kentucky Power Company, Kingsport Power Company, Michigan Power Company, Ohio Power Company, Union Electric Company, Wheeling Electric Company
447	D-475	D.L. Aswell (Louisiana Power and Light)
448	D-476	Charles L. Tyree (Oklahoma Gas and Electric Company)

TABLE 2-I (Continued)

No.	Docket No.	Commenters
449	D-477	W. Samuel Tucker, Jr. (Florida Power and Light Co.)
450	D-478	James H. Evans (The Business Roundtable)
451	D-479	Bert Roark (Dept. for Natural Resources and Environmental Protection, State of Kentucky)
452	D-480	A.H. Massah (Mobil Oil Corporation)
453	D-481	Verl R. Topham (Utah Power and Light Co.)
454	D-482	Charles A. Zielinski (Public Service Commission, State of New York)
455	D-483	Scott M. Turner (Nixon, Hargrave, Devans & Doyle, representing Rochester Gas and Electric Company)
456	D-484	Douglas L. McCrary (Southern Company Services, Inc.)
457	D-485	J.L. Morgan (The American Society of Mechanical Engineers)
458	D-486	E.R. Kilpatrick (Minnesota Power and Light Company)
459	D-487	Ernest P. Kline (Lieutenant Governor, State of Pennsylvania)
460	D-488	John D. Janak (Texas Utilities Services, Inc.)

TABLE 2-I (Continued)

No.	Docket No.	Commenters
461	D-489	David S. Potter (General Motors Corporation)
462	D-490	American Public Power Corporation
463	D-491	George C. Freeman, Jr. (Hunton and Williams, representing the Utility Air Regulatory Group)
464	D-492	Richard T. Myren (U.S. Resident)
465	D-493	William E. Culbreath, Jr. (Florida Lung Association)
466	D-494	Faith Hunt Tjardes (American Lung Association of Colorado)
467	D-495	Lauretta Rice (League of Women Voters of San Luis Obispo, California)
468	D-496	Patrick Brouty (U.S. Resident)
469	D-497	G. Richard Day (Kentucky Lung Association)
470	D-498	William C. Jacquin (Arizona Chamber of Commerce)
471	D-499	James W. Morrow (American Lung Association of Hawaii)
472	D-500	Mildred Engelberg (U.S. Resident)
473	D-501	Alexander Sagady (Michigan Lung Association)
474	D-502	Clive Mutschler (U.S. Resident)

TABLE 2-I (Continued)

No.	Docket No.	Commenters
475	D-503	Billie Dytzel (New Mexico Lung Association)
476	D-504	Lori Franklin (U.S. Resident)
477	D-505	Paul H. Arbesman (Dept. of Environmental Protection, New Jersey)
478	D-506	Emma Hartzler (U.S. Resident)
479	D-507	Brad Bortner (University of Vermont)
480	D-508	David B. Tegart (Western Environmental Trade Association, Inc.)
481	D-509	Evelyn Volpe (U.S. Resident)
482	D-510	Carl Pope (Sierra Club)
483	D-511	Arnold Miller (United Mine Workers of America)
484	D-512	Harold F. Elkin (Sun Company)
485	D-513	Richard C. Dolsemer (U.S. Resident)
486	D-514	James C. Wilson (Western Regional Council)
487	D-515	Donald B. Ricky (Mid-Valley Lung Association)
488	D-516	James L. Bechtold (Northern States Power Company)
489	D-517	Ethel Morten (U.S. Resident)

TABLE 2-I (Continued)

No.	Docket No.	Commenters
490	D-518	Diane Brown (League of Women Voters of Oklahoma)
491	D-519	Douglas L. McCrary (Southern Company Services, Inc.)
492	D-520	R. L. Hufman (Golden Valley Electric Assn., Inc.)
493	D-521	Ahti A. Erkkinen (U.S. Resident)
494	D-522	Fay Witz (City of Highland Park, Illinois)
495	D-523	E.R. Bingham (AMAX Environmental Services, Inc.)
496	D-524	John R. Bartlit (New Mexico Citizen for Clean Air and Water)
497	D-525	Clarence Petty (U.S. Resident)
498	D-527	Henry S. Reuss (U.S. House of Representatives) and James R. Underkofler (Wisconsin Power & Light Co.)
499	D-528	Clement J. Zablocki (U.S. House of Representatives) and James R. Underkofler (Wisconsin Power & Light Co.)
500	D-529	William J. Hughes (U.S. House of Representatives) and Jerrold Jacobs (Atlantic City Electric Co.)

TABLE 2-I (Continued)

No.	Docket No.	Commenters
501	D-530	S. I. Hayakawa (U.S. Senate) and Hugh W. Evans (U.S. Resident)
502	D-531	John J. LaFalce John Buchanan Tom Bevill Robert E. Badham Gunn McKay Walter Flowers G.V. Montgomery Henry J. Nowak Stanley N. Lundine (U.S. House of Representatives)
503	D-534	Millicent Fenwick (U.S. House of Representatives) and Jerrold L. Jacobs (Atlantic City Electric)
504	D-535	Robert W. Kastenmeier (U.S. House of Representatives) and James R. Underkofler (Wisconsin Power & Light Company)
505	D-536	Robert A. Roe (U.S. House of Representatives) and Jerrold L. Jacobs (Atlantic City Electric)
506	D-537	G. William Whitehurst Paul Trible (U.S. House of Representatives) and Harry F. Byrd, Jr. (U.S. Senate) and Stanley Ragone (Virginia Electric and Power Co.)

TABLE 2-I (Continued)

No.	Docket No.	Commenters
507	D-538	Gillespie V. Montgomery (U.S. House of Representatives) and V.J. Daniel, Jr. (Mississippi Power Company)
508	D-539	Les Aspin (U.S. House of Representatives) and Philip G. Sikes (U.S. Resident)
509	D-540	Lindy Boggs (U.S. House of Representatives) and J.M. Mooney (Louisiana Power and Light)
510	D-541	James O. Eastland (U.S. Senate) and V.J. Daniels, Jr. (Mississippi Power Company)
511	D-542	John C. Stennis (U.S. Senate)
512	D-543	J. Bennett Johnston (U.S. Senate) and J.M. Mooney (Louisiana Power and Light)
513	D-544	Gillis W. Long (U.S. House of Representatives) and J.M. Mooney (Louisiana Power and Light)
514	D-545	Thomas O'Neill, Jr. (U.S. House of Representatives) and William J. Cadigan (Massachusetts Electric)

TABLE 2-I (Continued)

No.	Docket No.	Commenters
515	D-547	Robert L. Livingston (U.S. House of Representatives)
516	D-548	Joel Pritchard (U.S. House of Representatives) and Don C. Frisbee (Pacific Power & Light Co.)
517	D-549	Jeffrey Nedelman (U.S. Senate) and Cecile Helsel (City of Superior, Wisconsin)
518	D-550	Gus Yatron (U.S. House of Representatives) and Walter M. Creitz (Metropolitan Edison Co.) and W.G. Kuhns (General Public Utilities Corp.)
519	D-551	Emery Nemethy (Ecology/Alert)
520	D-552	Malcolm Wallop (U.S. Senate)
521	D-553	John M. Daniel, Jr. (Commonwealth of Virginia, State Air Pollution Control Board)
522	D-554	Robert Hibbard (Pennsylvania Chamber of Commerce)
523	D-555	Margaret M. Heckler (U.S. House of Representatives) and William J. Cadigan (Massachusetts Electric)
524	D-556	Thad Cochran (U.S. House of Representatives)

TABLE 2-I (Continued)

No.	Docket No.	Commenters
525	D-557	Russell B. Long (U.S. Senate) and J.M. Mooney (Louisiana Power and Light)
526	D-558	Paul Findley (U.S. House of Representatives)
527	D-559	George C. Freeman, Jr. (Hunton & Williams representing Utility Air Regulatory Group)
528	D-560	Edward M. Kennedy (U.S. Senate) and William J. Cadigan (Massachusetts Electric Co.)
529	D-561	John Melcher (U.S. Senate)
530	D-562	Don Young (U.S. House of Representatives)
531	D-563	Warren G. Magnuson (U.S. Senate) and Don C. Frisbee (Pacific Power & Light Co.)
532	D-564	Reed Zars (Powder River Basin Resource Council)
533	D-565	Ethel W. Thorniley Mr. & Mrs. R. Poland Mr. & Mrs. L. Rusan Ms. D. Farman Mr. & Mrs. T. Szabo Mr. & Mrs. R. Angst Mr. & Mrs. G. Manz Mr. & Mrs. C. Paddock Mrs. N. Trost Mr. & Mrs. A. Morency (U.S. Residents)

TABLE 2-I (Continued)

No.	Docket No.	Commenters
534	D-566	Marty Bender (U.S. Resident)
535	D-567	Leilani Zutrau (U.S. Resident)
536	D-568	Wm. J. Basiliere (U.S. Resident)
537	D-569	Meg Titus (League of Women Voters of Texas)
538	D-570	Tracy Caldewey (U.S. Resident)
539	D-571	Frank Beal (State of Illinois, Institute of Natural Resources)
540	D-572	J. Stewart Frame (U.S. Resident)
541	D-573	Robert B. Ludgate (Pennsylvania Society of Professional Engineers)
542	D-574	Julio Hernandez-Fragoso (Puerto Rico Water Resources Authority)
543	D-575	A. E. Michon (Burlington Northern)
544	D-576	Helen Jacobs (Southeastern Wisconsin Coalition for Clean Air, Technical Committee)
545	D-577	Robert S. Anderson (U.S. Resident)
546	D-578	Peter S. Duncan (Commonwealth of Pennsylvania, Joint Legislative Air and Water Pollution Control and Conservation Committee)

TABLE 2-I (Continued)

No.	Docket No.	Commenters
547	D-579	Ed Herschler (Governor of Wyoming)
548	D-580	John J. Bugas (Colorado-Ute Electric Association, Inc.)
549	D-581	Julian M. Carroll (Governor of Kentucky)
550	D-582	John A. Scarola (Ebasco Services)
551	D-583	James L. Grahl (Basin Electric Power Cooperative)
552	D-584	Joseph S. Ives (National Rural Electric Cooperative Association)
553	D-585	W.G. Hegener (Sargent & Lundy Engineers)
554	D-586	William F. Zunker (CNB Tri-Fuel Boiler)
555	D-587	Abe H. Frumkin, Esq. (representing the Anthracite Development and Utilization Association)
556	D-588	D.F. Barrett (E.I. DuPont De Nemours & Company)
557	D-589	Leroy Michael, Jr. (Salt River Project)
558	D-590	Patricia Schroeder (U.S. House of Representatives)
559	D-591	Gary L. Allison (Wheelabrator Chemical Corp.)
560	D-592	Rafe Pomerance (National Clean Air Coalition)

TABLE 2-I (Continued)

No.	Docket No.	Commenters
561	D-593	James L. Bechthold (Northern States Power Company)
562	D-594	Kay Troitino (U.S. Resident)
563	D-595	G. William Whitehurst Robert W. Daniel, Jr. (U.S. House of Representatives) and Durwood S. Curling (Southeastern Public Service Authority of Virginia)
564	D-596	Mark O. Hatfield (U.S. Senate) and Don C. Frisbee (Pacific Power & Light Company)
565	D-597	Tom Quinn (California Governor's Office)
566	D-598	Bill Proxmire (U.S. Senate) and Cecile Helsel (City of Superior, Wisconsin)
567	D-599	David C. Treen (U.S. House of Representatives)
568	D-600	Mark O. Hatfield (U.S. Senate) and Kenneth W. Self (Freightliner Corporation)
569	D-601	Lewis C. Green (Green, Hennings & Henry representing the Coalition for the Environment)
570	D-602	William B. Harral (Commonwealth of Pennsylvania, Governor's Office)

TABLE 2-I (Continued)

No.	Docket No.	Commenters
571	D-603	Henry V. Nickel (Hunton & Williams representing the Utility Air Regulatory Group)
572	D-604	Not a comment letter
573	D-605	Gaylord Nelson (U.S. Senate)
574	D-606	Dennis G. Seipp (Coal Coordinator, Commonwealth of Pennsylvania)
575	D-607	Vincent B. Makowski (Solicitor, Borough of Marion Heights, Pennsylvania)
576	D-608	Frank L. Blackhall (U.S. Resident)
577	D-609	Gary Rubenstein (State of California Air Resources Board)
578	D-610	William E. Albers (The Appalachian Regional Commission)
579	D-611	Henry V. Nickel (Hunton & Williams representing the Utility Air Regulatory Group)
580	D-612	Ray Thornton (U.S. House of Representatives) and Arch Pettit (Arkansas Power & Light Company)
581	D-613	Harold T. Johnson (U.S. House of Representatives)
582	D-614	David R. Bowen (U.S. House of Representatives)

TABLE 2-I (Continued)

No.	Docket No.	Commenters
583	D-615	Lawton Chiles (U.S. Senate) and E.L. Addison (Gulf Power Company)
584	D-616	William H. Harsha (U.S. House of Representatives)
585	D-617	Mark O. Hatfield (U.S. Senate) and William W. Lyons (Northern Energy Resources Co.)
586	D-618	Les AuCoin (U.S. House of Representatives) and William Lyons (Northern Energy Resources Co.)
587	D-619	Robert R. Wahler (Wahlco)
588	D-620	W.M. Irving (Jacksonville Electric Authority)
589	D-621	Peter J. Walley (Mississippi Fuel & Energy Management Commission)
590	D-622	Daniel Shubert, M.D. (U.S. Resident)
591	D-623	Merilyn Reeves (American Lung Association of Maryland, Inc.)
592	D-624	Michael Laurie (U.S. Resident)
593	D-625	H. E. Bond (Atlantic Richfield Company)
594	D-626	Joseph J. Brecher (representing The Sierra Club)

TABLE 2-I (Continued)

No.	Docket No.	Commenters
595	D-627	J. Louis York (Stearns-Roger, Inc.)
596	D-628	Gene H. Glockley (PP&L)
597	D-629	C. Frank Horscher, III (Dept. for Natural Resources and Environmental Protection, Commonwealth of Kentucky)
598	D-630	Joseph W. Mullan (National Coal Association)
599	D-631	Richard E. Ayres (Natural Resources Defense Council; Environmental Defense Fund)
600	D-632	George P. Green (Public Service Co. of Colorado)
601	D-633	Joseph J. Brecher (representing Pacific Gas and Electric Company)
602	D-634	J. Kenneth Robinson (U.S. House of Representatives)
603	D-635	Frank Moore (Asst. to the President) and John C. Stennis (U.S. Senate) and Donald C. Lutken (Mississippi Power and Light)
604	D-636	Paul Simon (U.S. House of Representatives)

TABLE 2-I (Continued)

No.	Docket No.	Commenters
605	D-637	Frank Moore (Asst. to the President) and Thad Cochran (U.S. House of Representatives) and V. J. Daniel, Jr. (Mississippi Power Company)
606	D-638	John Tower (U.S. Senate) and Philip D. English (Broventure Company, Inc.)
607	D-639	Lloyd Bentsen (U.S. Senate)
608	D-640	Lawton Chiles (U.S. Senate) and Norman O. Stern (American Lung Assn. of Broward-Glades-Hendry, Inc.)
609	D-642	Matthew F. McHugh (U.S. Representative) and E. Eugene Forrest (New York State Electric and Gas Corporation)
610	D-643	Robert L. Livingston (U.S. House of Representatives)
611	D-644	Robert R. Wohler (WAHLCO)
612	D-645	Elizabeth Johnson (Coalition for the Environment)
613	D-646	Wilma T. Kennell (U.S. Resident)
614	D-648	Thomas A. Vanderslice (General Electric Company)

TABLE 2-I (Continued)

No.	Docket No.	Commenters
615	D-649	Ray Thornton (U.S. House of Representatives) and Arch P. Pettit (Arkansas Power and Light Co.)
616	D-650	H. T. Johnson (U.S. House of Representatives)
617	D-651	Scott Matheson (Governor of Utah)
618	D-652	Pamela Zinn (The White House) and John R. Hamann (Detroit Edison)
619	D-653	Gus Yatron (U.S. House of Representatives)
620	D-654	J. Hernandez-Fragoso (Puerto Rico Water Resources Authority)
621	D-655	Meg Titus (League of Women Voters)
622	D-656	R. L. White (Texas Utilities Generating Co.)
623	D-657	M. P. Lanahan (N.Y. Dept. of Environmental Conservation)
624	D-658	Arlan Stangeland (U.S. House of Representatives) and James L. Grahl (Basin Electric Power Cooperative)
625	D-659	Liz Stajduhar (U.S. Resident)
626	D-660	William W. Scranton, III (Lt. Governor, State of Pennsylvania)

TABLE 2-I (Continued)

No.	Docket No.	Commenters
627	D-661	M. Ardell (U.S. Resident)
628	D-662	Ted Stevens (U.S. Senate) and R.L. Hufman (Golden Valley Electric Assn., Inc.)
629	D-663	M. Diana Gyllenhammar (U.S. Resident)
630	D-664	B. G. Myott (Montana Power Co.)
631	D-665	J. M. Carroll (Governor of Kentucky)
632	D-666	Mary Lynn (U.S. Resident)
633	D-667	Thad Cochran (U.S. Senate) and John R. Craft J. Stewart Frame Thomas A. Dallas (U.S. Residents)
634	D-668	Patricia Senft (U.S. Resident)
635	D-669	Milton R. Young (U.S. Senate) and James L. Grahl (Basin Electric Power Cooperative)
636	D-670	Richard E. Hug (Environmental Elements Corp.)
637	D-671	J. J. Brecher (U.S. Resident)

TABLE 2-I (Continued)

No.	Docket No.	Commenters
638	D-672	Ken Kramer (U.S. House of Representatives) and John J. Bugas (Colorado-Ute Electric Assn., Inc.)
639	D-673	W. E. Stephenson (Paluszek & Leslie Associates)
640	D-674	Graham H. Tempel (U.S. Resident)
641	D-675	April Sanders (U.S. Resident)
642	D-676	David Pryor (U.S. Senate) and Arch Pettit (Arkansas Power & Light)
643	D-677	Trent Lott (U.S. House of Representatives) and J. Stewart Frame (U.S. Resident)
644	D-678	John A. Durkin (U.S. Senate) and Russell A. Holden (New England Power Company)
645	D-679	John C. Stennis (U.S. Resident) and David J. Bridgers (U.S. Resident)
646	D-680	Mark Andrews (U.S. House of Representatives)
647	D-681	Thad Cochran (U.S. Senate) and David S. Bridgers (U.S. Resident)

TABLE 2-I (Continued)

No.	Docket No.	Commenters
648	D-682	John Glenn (U.S. Senate) and LeRoy S. Harris (The American Society of Mechanical Engineers)
649	D-683	Barry Goldwater Dennis DeConcini (U.S. Senate)
650	D-684	Dick Cheney (U.S. House of Representatives)
651	D-685	J. James Exon (U.S. Senate) and James L. Grahl (Basin Electric Power Cooperative)
652	D-686	Virginia Smith (U.S. House of Representatives) and James L. Grahl (Basin Electric Power Cooperative)
653	D-687	Lester L. Wolff (U.S. House of Representatives) and Leilani Zutrau (U.S. Resident)
654	D-688	Catherine Roberts (Planning Office of Crested Butte, Colorado)
655	D-689	Richard Schweiker (U.S. Senate) and Vincent Makowski (Solicitor, Borough of Marion Heights, Pennsylvania)
656	D-690	Gus Yatron (U.S. House of Representatives) and William Wickert, Jr. (Bethlehem Steel Corporation)

TABLE 2-I (Continued)

No.	Docket No.	Commenters
657	D-691	M. Child (U.S. Resident)
658	D-692	Not a comment letter
659	D-693	Not a comment letter
660	D-694	John J. Rhodes Bob Stump Eldon Rudd (U.S. House of Representatives)
661	D-695	Richard S. Schweiker (U.S. Senate)
662	D-696	Not a comment letter
663	D-697	C. Oliver (U.S. Resident)
664	D-698	G.C. Freeman, Jr. (Hutton & Williams)
665	D-699	Utility Air Regulatory Group (UARG)
666	D-700	G.C. Freeman, Jr. (Hutton & Williams)
667	D-701	Not a comment letter
668	D-702	Paul S. Sarbanes (U.S. Senate) and Richard E. Hug (Environmental Elements Corp.)
669	D-703	J.E. Bicker (McCone WIFE)
670	D-704	N.D. Grasmehr (League of Women Voters of Ventura County)

TABLE 2-I (Continued)

No.	Docket No.	Commenters
671	D-705	R. Guenther (U.S. Resident)
672	D-706	J.B. Roy (U.S. Resident)
673	D-707	Tennyson Guyer (U.S. House of Representatives)
674	D-708	M.W. Steinberg (U.S. Resident)
675	D-709	E.R. Edie (South Dakota Resources Coalition)
676	D-710	J. Dembeck (U.S. Resident)
677	D-711	Y. Maxon (The Planning and Conservation League)
678	D-712	B. Rutemoeller (U.S. Resident)
679	D-713	E. Copley (U.S. Resident)
680	D-714	N. Macy K. Macy (U.S. Residents)
681	D-715	L. Solomon (U.S. Resident)
682	D-716	Charles McC. Mathias, Jr. (U.S. Senate) and Richard E. Hug (Environmental Elements Corp.)
683	D-717	S. McAvoy (Illinois Environmental Council)
684	D-718	S. Gayner (U.S. Resident)

TABLE 2-I (Continued)

No.	Docket No.	Commenters
685	D-719	P.G. Robinson (Southwest Environmental Service)
686	D-720	E. Rosen (U.S. Resident)
687	D-721	L. Sprague (U.S. Resident)
688	D-722	T. Dobson (Public Interest Research Group in Michigan)
689	D-723	P. Haworth (U.S. Resident)
690	D-724	P. Stuart (Powder River Basin Resource Council)
691	D-725	George C. Freeman, Jr. (Hutton & Williams)
692	D-726	A. Bruno-Vega (Puerto Rico Water Resources Authority)
693	D-727	C.R. Feldman (Americans for Energy Independence)
694	D-728	L. Lewis (Sierra Club, Grand Canyon Chapter, Arizona)
695	D-729	D.F. Weiss (U.S. Resident)
696	D-730	E. Sonoga (U.S. Resident)
697	D-731	Not a comment letter
698	D-732	Robert H. Michel (U.S. House of Representatives) and Illinois Power Company

TABLE 2-I (Continued)

No.	Docket No.	Commenters
699	D-733	Thad Cochran (U.S. Senate) and G. Adam (U.S. Resident)
700	D-734	Not a comment letter
701	D-735	R.L. Emrich (First Presbyterian Church of Greensburg, PA)
702	D-736	Not a comment letter
703	D-737	Not a comment letter
704	D-738	Unsigned (U.S. Resident)
705	D-739	Not a comment letter
706	D-740	K. Katzenstein (U.S. Resident)
707	D-741	Not a comment letter
708	D-742	John Melcher (U.S. Senate)
709	D-743	R.J. Rauch (Environmental Defense Fund)
710	D-744	G.C. Freeman, Jr. (Hunton & Williams)
711	D-745	Paul Simon (U.S. House of Representatives) and H.L. Deakins (Illinois Power Company)
712	D-746	Dale Bumpers (U.S. Senate)

TABLE 2-I (Concluded)

No.	Docket No.	Commenters
713	D-747	S. Flanigan (U.S. Resident)
714	D-748	Not a comment letter
715	D-749	E.D. Fillmore (League of Women Voters of Southeastern Pennsylvania Region)
716	D-750	C. Frisch N. Lederer (League of Women Voters of Detroit)
717	D-751	E.J. Stanek L.E. Crane (Iowa Energy Policy Council)
718	D-752	R.E. Hug (Environmental Elements Corp.)
719	D-753	F. Beal D.J. Goodwin (Illinois Institute of Natural Resources)
720	D-754	H.E. Bond (Atlantic Richfield Company)
721	D-755	J.R. Thompson (State of Illinois, Office of the Governor)
722	D-756	C.E. Bagge (National Coal Assn.)

TABLE 2-II

LIST OF PERSONS PRESENTING TESTIMONY AT THE PUBLIC HEARING

No.	Docket No.	Commenters
1	F-1aa	Walter Markey (Gilbert Commonwealth)
2	F-1b	John W. Ross (Montana Power Co.)
3	F-1bb	Leonard V. Ziolkowski (Economic Development Council)
4	F-1c	Joseph F. Brecher (representing The Sierra Club)
5	F-1cc	William Savinsky (United Mine Workers of America)
6	F-1d	James McCarville (City of Superior, Wisconsin)
7	F-1dd	Robert Lazarchik (Joint Authority Committee)
8	F-1e	Al Johnson (Johnson Brothers Corporation)
9	F-1ee	George Gensemer (SEDA - Council of Governments)
10	F-1ff	Frank Zukas (Greater Pottsville Area Chamber of Commerce)
11	F-1g	George Greene (Public Service Company of Colorado)
12	F-1i	Carl M. Shy, M.D. (American Lung Association)
13	F-1j	Meg Titus (League of Women Voters of the U.S.)
14	F-1l	Reverend Bruce Tischler (Joint Program Agency of Lehigh and Lackawanna Presbyteries of the United Presbyterian Church)

TABLE 2-II (Concluded)

No.	Docket No.	Commenters
15	F-1n	Robert Rauch (Environmental Defense Fund)
16	F-1o	Daniel Schwartzman (Health Resources Management, University of Illinois, School of Public Health)
17	F-1q	Thomas G. Healy (National Coal Association)
18	F-1r	William Albers (Appalachian Regional Commission)
19	F-1s	B. G. Godec (Utilities of the City of Colorado Springs)
20	F-1t	Richard Ayers (NRDC)
21	F-1u	George C. Freeman, Jr. (Utility Air Regulatory Group)
22	F-1w	John R. McNamara (Power Salt River Project)
23	F-1x	Raymond E. Kary, Ph.D. (Arizona Public Service Corp.)
24	F-1y	Dennis Eyre (Western Systems Coordinating Council)
25	F-1z	Irwin Tucker (Professor, Univ. of Louisville)
26	F-2	George P. Green (Public Service Company of Colorado)
27	F-3	Allen E. Ertel (U.S. House of Representatives)

TABLE 2-III

LIST OF OFFICIAL WRITTEN COMMENTS FROM OTHER FEDERAL ORGANIZATIONS

No.	Docket No.	Commenters
1	H-5	William V. Skidmore (General Council of Commerce)
2	H-6	Deputy Assistant Secretary (United States Department of the Interior)
3	H-8	Acting Director of the National Park Service
4	H-9	S. David Freeman (Tennessee Valley Authority)
5	H-10	John F. O'Leary (Department of Energy)
6	H-11	Cecil D. Andrews (U.S. Department of the Interior)
7	H-12	Barry P. Bosworth (Council on Wage and Price Stability)
8	H-13	William V. Skidmore (General Counsel of the U.S. Department of Commerce)
9	H-14	Daniel Badger (Department of Energy)
10	H-15	Jerry Pell (Anthracite Division, Office of Coal Supply, Dept. of Energy)
11	H-17	John F. O'Leary (Department of Energy)
12	H-19	Bob Bergland (Department of Agriculture)

2.2 Administrative and Procedural Actions

1. D-231

Comment: On page 42117 Section 60.40(a)(3) should read "(3) Not subject to."

2. D-231

Comment: On page 42180 in the formula for F_d there should be a plus sign instead of a multiplication sign at 35.4 (%S) x 8.6 (%N).

3. D-231

Comment: On page 42182 the formula for F_w is missing a plus (+) sign between 0.14(%N) and 0.46(%O).

4. D-203

Comment: The formula for determining the NO_x standard for mixed fuels in section 60.44a(d) is missing an "equals" sign between PS_{NOx} and w(86).

5. D-417

Comment: Evaluation of costs and non-air quality impacts have not been done with regard to oil-fired unit regulations.

6. D-461

Comment: NO_x and particulates have fuel specific regulations while SO_2 has a single uniform regulation. This appears to be inequity in the uniform approach.

7. D-626

Comment: Adequate opportunity to review all the data has been provided by EPA.

8. D-628

Comment: A number of procedural comments regarding the data published in the Federal Register for the first time on December 8, 1978 are:

- How can a response be made to data which may not be reliable because EPA's technical staff has not verified it?
- There is an inconsistency in the description of the sixth alternative between the subtitle section "Sliding Scale with 90 percent Control in West" and the discussion following which describes 50 percent control.
- Are the 3 alternatives - 95 percent SO_2 reduction, 90 percent reduction, and seven options for partial scrubbing - designed to support the September proposals or are they new control proposals in themselves?
- The required economic and energy assessments mandated by Section 307 of the Clean Air Act Amendments have not been provided for the new alternatives presented in the December addendum.
- In the December information, costs of complying with various alternatives were combined into one cost figure so that the economic effect of costs for SO_2, NO_x and particulates standards cannot be separately considered or responded to.

9. D-491, D-629, D-698

Comment: Under section 307(d) of the Clean Air Act, EPA is required to provide adequate opportunity for public review and comment on proposed rules. Based on the relative importance of this standard, insufficient time was allotted for public comment.

10. D-491, F-1u

Comment: Under section 307(d) of the Clean Air Act, EPA has an obligation to disclose fully at the time it publishes a proposed NSPS the entire record upon which it bases its proposal. EPA has failed to comply with these requirements. This could have the effect of legally invalidating the entire rulemaking procedure.

11. D-491

Comment: The public hearing held on December 12-13 should have provided the public with an opportunity to explore the EPA background and rationale for the proposed standard. Instead the hearing disclosed the bases for the positions taken by all participants except EPA, the only participant with a statutory obligation to disclose its basis.

12. D-743

Comment: A method to prevent ex parte communications is presented for consideration.

13. D-753

Comment: EPA has failed to provide adequate and timely information to potentially affected parties.

2.3 Affected Facility

2.3.1 - 60.40a Applicability and Designation of Affected Facility

General Comments on Applicability

1. D-409

Comment: The proposed regulations create a "double standard" by not covering all fossil fuel fired steam generators. Only electric utility plants are covered by the proposed standard. Commenter questions legality of this under Section 111 of Clean Air Act.

2. D-490

Comment: The unit size threshold should be established as 1250 x 10^6 Btu/hr instead of 250 x 10^6 Btu/hr due the hardship imposed on small utilities.

Combined Cycle Facilities

1. D-253

Comment: Only total stack emissions should be regulated in combined cycle facilities rather than turbine emissions under a separate subpart and boiler emissions under subpart Da as proposed.

Cogeneration Facilities

1. D-280

Comment: The regulations discriminate against cogeneration. Units producing less than 25 MWe for commercial use should be exempt regardless of capacity of boiler.

2. D-412, D-423

Comment: The interpretation of the definition of "Electric Utility Steam Generating Unit" as applied in the preamble is a misinterpretation of the definition because,

- the interpretation of electric cogeneration units is not in keeping with the categorization of boilers in power plants as opposed to industrial plants as given in Section 111 of the Clean Air Act.
- the interpretation of electric cogeneration unit fails to take into consideration the second sentence of the definition of electric utility steam generating unit which if applied would increase the electrical energy output of the cogeneration plant for purposes of determining the percentage of electricity sold to the public
- the proposed rules provide a credit for pretreatment of fuel to remove sulfur or increase its heat content; yet

the interpretation fails to take into account the higher utilization of the heat content of the fuel in the cogeneration plant compared to the power plant

- the interpretation unduly expands the meaning of "sale" found in the definition. Many units use an accounting system of "selling" all the electricity produced to a grid and then "buying" electricity from the grid for in-house use

3. D-448

Comment: The regulation is too restrictive for emerging technology (e.g., the proposed NSPS would kill a project to use a calcining kiln to generate 70 MWe).

4. D-460

Comment: Two identical boilers, one used for industrial and in-plant electrical generation, the other used for commercial electric generation will have different standards, discriminating against utilities. This will cause an increase in in-plant electrical generation and increased pollution.

5. D-490

Comment: Cogeneration and alternate fuels should be exempt from regulations or the threshold of applicability be raised (no suggested level given). This would encourage use of this energy efficient process.

Resource Recovery Facilities

1. D-28

Comment: Refuse derived fuel should be included under the standard since there is no difference between sulfur in coal and sulfur in refuse.

2. D-259, D-449, D-490

Comment: Refuse derived fuel should be exempt to encourage development of such usage.

3. D-423

Comment: All resource recovery units should be exempt from SO_2 percentage removal requirement in order to encourage use of these fuels.

4. D-483

Comment: The current NSPS specifically exempts units modified to use non-fossil fuel but proposed regulations do not. This provision should be included.

5. D-595

Comment: The proposed standards should not be made applicable to a new solid waste processing plant from which steam and electricity would be sold to the U.S. Naval shipyard in Portsmouth, Va. Boilers will normally be fired with 97 percent refuse derived fuel and 3 percent coal although under most conditions up to 21 percent coal might be burned a few days per year. The plant would be jeopardized by cost of scrubbers and lack of space to accomodate them on the available property. Making standards applicable to plant would frustrate innovative technology addressing energy and solid waste problems.

Commenced Construction

1. D-33

Comment: The regulation should be extended to include existing plants.

2. D-370

Comment: Clarification is needed to show that the regulation does not apply to existing plants or plants clearly under construction.

3. D-153, D-463, F-16

Comment: The applicability section which designates September 18, 1978, as the specific cutoff date for commencement of construction or modification should be amended to create a reasonable transition period for those facilities which received all necessary design and preconstruction approvals, including current NSPS, SIP and PSD review. Failure to allow this transition would have severe inflationary impacts if time delays and/or redesign or rereview of plans becomes necessary.

4. D-585

Comment: We believe that administrative due process requires the applicability of the regulations to be readily determinable. The proposed regulations did not include any discussion of what act or acts constitute "commencement of construction." We favor a precise applicability definition that would include either:

- commitment to a site
- purchase of a major component

Modification

1. D-280, D-203, D-204

Comment: Preamble discussion on modifications (pg 42158) is not reflected in regulations.

2. D-369

Comment: Modification which consists solely of installation of flue gas cleaning equipment should not be considered to be an NSPS modification.

3. D-224, D-404

Comment: Older gas-fired units forced to fuel switch due to gas shortages should not be considered to be an NSPS modification.

4. D-259, D-628

Comment: A clearer description of modification should be given so that energy conservation upgrading is not penalized.

5. D-397, F-1b

Comment: The standard should include a statement that if a change in a facility or its pollution control equipment would result in less emissions being discharged into the atmosphere or improved ambient air quality, such change is not considered a modification.

6. D-467

Comment: Modification of oil or coal units to burn wood and refuse derived fuels should not be considered as an NSPS modification. This change would encourage conversion to these alternate fuels.

2.3.2 - 60.41a Definitions

Electric Utility Steam Generating Unit

1. D-153

Comment: If industrial boilers are exempt, small utility (e.g., 100 MW) should be also.

2. D-467, D-491

Comment: The term "steam generating unit" is defined in section 60.41a(a) to exclude nuclear steam generators. This is inconsistent with section 60.41a(k) where the term "steam electric generating unit" specifically includes nuclear power plants. Removing the word "steam" in section 60.41a(k) would alleviate the inconsistency.

Utility Company

1. D-223

Comment: The definition of "utility company" should be clarified to distinguish it from an "owner or operator" as defined at 60.2(f). For example: "utility company" as applied to the determinations of the existence of an "emergency condition" means the largest organization, business, or governmental entity that owns the affected facility (e.g. a holding company with operating subsidiary companies).

System Capacity

1. D-253, D-491

Comment: The present definition excludes hydroelectric and geothermal power.

2. D-413

Comment: The definition should ensure that net plant capacity and not rated capacity is used to determine whether or not an emergency exists.

3. D-491

Comment: The definition of system capacity (section 60.41a(j)) should include firm contractual purchases and should exclude firm contractual sales. The following change is suggested to the last sentence,

> "The electrical generating capacity of electric generating equipment under multiple ownership is prorated based on ownership unless the proportional entitlement to electricity generated by that capacity is otherwise established by contractual arrangement."

System Emergency Reserves

1. D-253

Comment: The definition appears to refer to the largest single unit in the system, but it is not clear whether or not the unit is on-line and carrying load. Suggests it should be the largest on-line unit that is considered the largest unit.

2. D-413

Comment: The definition should account not only for the capacity of the single largest generating unit, but also for reserves needed for system load-frequency regulations.

3. D-491

Comment: Under 60.41a(k) the last sentence should be modified to read,

> "The electrical generating capacity of electric generating equipment under multiple ownership is prorated based on ownership unless the proportional entitlement to electricity generated by that capacity is otherwise established by contractual arrangement."

Available System Capacity

1. D-467

Comment: The definition of available system capacity should be modified to read "the capacity determined by subtracting the system load, the system emergency reserves, firm transactions, and unit power commitments from the system capacity." This change will take into account capacity which is owned by one utility but committed for use by contract to another utility upon conditions which prohibit the electricity sold from being withdrawn. Such electricity is unavailale to the selling utility for the life of the contractual arrangement.

2. D-491

Comment: Some utilities have certain localized areas or zones within the general areas which they service which, due to system operating parameters, cannot be served by all of the generating units which constitute the utility's system capacity. As a result, an affected facility may be the only source of supply for a zone or area even though there is one capacity in the system. The proposed regulations should explicitly allow deduction from system capacity of any capacity which cannot be used to meet system load in a particular area or zone.

Spinning Reserve

1. D-491

Comment: Under paragraph 60.41a(m) the last sentence should be modified to read,

> "The electrical generating capacity of electric generating equipment under multiple ownership is prorated based on ownership unless the proportional entitlement to electricity generated by that capacity is otherwise established by contractual arrangement."

Emergency Condition

1. D-253

Comment: The paragraph title should be reworded to "Flue Gas Desulfurization Emergency Conditions" to distinguish from electrical system emergencies.

2. D-253

Comment: It would appear that a utility would have to shut down a unit with a malfunctioning FGD module if there were other units down for fuel conservation or in cold storage. It is suggested that this section be changed to read: "one or more electric generating units held in spinning reserve or cold standby reserve, or ..."

3. D-320

Comment: Emergency bypass conditions for sulfur dioxide scrubbers should be determined by the number of units on line at the time of the emergency occurrence.

4. D-373

Comment: The load switching requirement makes oil or gas-fired generators a control technology.

5. D-404, D-417, D-437

Comment: EPA should recognize that factors in addition to equipment malfunction (e.g., lack of fuel) can limit the availability of a generating unit.

6. D-409

Comment: In the absence of emergency conditions, a facility with a malfunctioning FGD system should be exempt from the percent reduction requirement if it cannot be met. The maximum limit of 1.2 lb/10^6 Btu would still apply.

7. D-413

Comment: The regulations do not allow for the severity of a malfunction. Partial failure of a FGD should be compensated for by limiting generation from the affected units and not removing them from service.

8. D-413, D-447

Comment: The regulations should give consideration to the possibility that an emergency may occur shortly after an affected unit is removed from service.

9. D-459

Comment: Justification for the three 24-hour exemptions of the 85 percent reduction requirement is not given in the background document.

10. D-467

Comment: This definition has not been defined broadly enough to encompass potential emergency situations associated with the generation, transmission and distribution of electricity. At a minimum the definition should be modified to include long term fuel shortages as well as short term capacity shortages in neighboring utility systems where a system voltage reduction would result if the scrubber could not be bypassed.

11. D-486

Comment: Present requirements for emergency conditions may produce negative results by forcing use of uncontrolled peaking units. Recommend a grace period upon failure of control.

12. D-491

Comment: The standard should recognize that a utility may need to keep a unit in operation (or bring a unit on line) because an emergency condition is projected for that day or the next calendar day. The orderly startup or shutdown of a unit requires up to eight to twelve hours under some conditions. To allow for this "look ahead," section 60.41a(n) should be changed by adding the following words at the end of section 60.41a(n)(1):

"when such conditions are projected to occur at any time through the next calendar day."

2.3.3 - Special Issues

Anthracite Coal

1. D-21, D-80, D-259, D-326, D-343, D-402, D-409, D-419, D-420, D-422, D-424, D-444, D-465, D-511, D-554, D-573, D-578, D-584, D-587, D-602, D-606, D-607, D-653, D-660, D-695, D-735, F-1a, F-1l, F-1r, F-1cc, F-1dd, F-1ee, F-1ff, H-10, H-15

Comment: Anthracite coal should be exempt from SO_2 regulations or a special standard established because:

- natural low sulfur content will have little impact on SO_2 emissions
- standard would encourage use of high sulfur coal
- reopening and reclamation of anthracite mines would encourage or require strict land reclamation which is beneficial and will result in cleaning up of culm piles
- economic benefit to anthracite region
- unproven controls on anthracite
- other fuels (e.g., lignite) have related standards
- since NO_x standard does not mention anthracite, precedent for exemption already exists
- less stringent standard will permit anthracite to compete with other sources of coal which are cheaper to mine
- would produce no more SO_2 emissions with exemption from scrubbing than high sulfur bituminous coal with full scrubbing
- anthracite is at a competitive disadvantage because it is almost entirely obtained from deep mining of previously worked areas
- improved water quality as a result of alleviating existing acid-mine drainage problems

- improved safety as a result of eliminating subsidence problems

2. D-343

Comment: The standard unfairly precludes the use of anthracite

3. D-134, F-3

Comment: Full scrubbing is economically disadvantageous to anthracite coal.

4. D-122

Comment: Contrary to popular belief, the averge sulfur content of Pennsylvania anthracite coal is 1.09 percent, which would not meet NAAQS. (presents survey data)

5. D-439, D-551, D-729

Comment: Anthracite coal should not be exempt because:

- drilling data (1977) indicates sulfur content at 1.1% S
- uncontrolled emissions would exceed 1.2 lb/10^6 Btu

6. D-487, D-610

Comment: The standard for anthracite coal should be 1.0 lb SO_2/10^6 Btu (floor) in order to:

- improve water quality in region
- reduce subsidence
- encourage reclamation and restoration of abandoned mine areas
- stimulate anthracite industry
- increase employment
- increase water supply

7. D-552

Comment: Problems which these proposed regulations present for utilities burning both anthracite and western sub-bituminous coal, though not identical, are similar. Anthracite is in fact a "local" coal. Western sub-bituminous will be used in many areas where there is in fact no "local" coal. Thus, under the Act, the fuel characteristics of both coals might be taken into consideration in establishing percentage reduction requirements for steam generating units in certain geographic market areas.

8. H-15

Comment: Anthracite has more problems with particulates than do other types of coal. Therefore anthracite coal must continue to meet all particulate standards, even if scrubbers for SO_2 should not be required under special provisions of the standard applicable to anthracite.

9 F-1a

Comment: The State of Pennsylvania has an ongoing large-scale project for massive reclamation and rehabilitation at several abandoned anthracite sites proposed for reopening. One area involves 12,000 to 19,000 acres of despoiled land. Financial resources are already being assembled to cover costs at the first site. This effort indicates clearly the potential environmental gains which are possible if a federal incentive such as exemption of anthracite coal from the SO_2 standard is provided.

Noncontinental Areas

1. D-159, D-366

Comment: Noncontinental U.S. should be exempt from the SO_2 standard for cost/benefit reasons.

2. D-283

Comment: Section 60.43a (c)(2) should be changed to include "and has to the satisfaction of the Administrator demonstrated that there is no alternative to using oil as fuel."

3. D-574

Comment: Non-continental areas should be exempt from the SO_2 standard because:

- limited land area for sludge disposal
- Puerto Rico population density of 900 persons/square mile
- can use low sulfur coal to replace oil
- unique meteorological conditions for atmospheric dispersion without ground-level increase in SO_2 concentration

4. D-726

Comment: If EPA considers lowering the ceiling to less than 1.2 lb/10^6 Btu, they should be aware that this will negate any exemption from the 85% reduction requirement because the lower emission ceiling will require scrubbing.

Alaskan Coal

1. D-150, D-366, D-520, D-562

Comment: Alaskan coal should be exempt from the SO_2 standard because:

- Alaskan coal is 0.25 percent sulfur
- Economics of lime transportation
- Sludge disposal
- technology is incapable of removing 85 percent of sulfur from 0.25 percent sulfur coal
- difficulties of operating wet scrubbers and disposing of sludge with ambient temperatures of 50°F below zero.
- utilities burning high sulfur coal could comply with proposed regulations and still emit substantially more SO_2 than Alaskan coal with no removal whatsoever.

2. D-608

Comment: Heavy media washing of the Western subbituminous coals from Colstrip County, Montana, may yield a coal also unique in its low sulfur content and reduced ash content. This coal could also be a candidate for the less stringent standards being considered for anthracite and Alaska coal.

3. D-631

Comment: Exempting Alaskan plants from the percentage reduction would be illegal under the uniform percentage reduction provision of the law. Therefore it should not be done.

4. D-562

Comment: Alaskan coal should be exempt from the SO_2 standard. The proposed rationale for exempting Hawaii should be extended to Alaska. The Alaskan airshed, fuel supply, electrical grid and transportation network are not common to the rest of the United States.

Emerging Technology

1. D-50, D-168, D-216, D-255, D-315, D-343, D-418, D-491

Comment: The requirement for FGD discourages alternate technology development because:

D-343; multi-stream coal cleaning is precluded

D-255; use of biomass fuel is precluded

D-50; proposed granting exemptions on case by case basis

D-491; SRC, dry scrubbers, fluidized bed combustion are precluded

2. D-223, D-369, D-245, [illegible]-259

Comment: The regulations do not address the development of innovative pollution control technology (for example, dry scrubbing not listed).

3. D-280

Comment: The standard should state 15,000 MW at 70 percent load to adjust for various load factors

4. D-280

Comment: The standards establish a minimum allocation for any other technique not specifically mentioned

5. D-280

Comment: SRC I should be under solvent refined coal and not coal liquefaction

6. D-280

Comment: The preamble should not limit number of demonstrations since the standard does not.

7. D-280

Comment: An additional section 60.45a(e) should be included: if technology is not working, plant must meet 0.8 lb/10^6 Btu (e.g., start up, malfunction, etc.)

8. D-280

Comment: The standard should provide that the 80 percent reduction allowed in Section 60.45a will be calculated in the same manner as the overall standard for regular power plants, including quarterly averaging when the emerging technology involves fuel pretreatment.

9. D-280

Comment: The preamble suggests that Section 60.45a only concerns bituminous coal

10. D-373

Comment: "Emergency Technologies" should include alternative technologies on page 42160.

11. D-413, D-455, D-585, H-10

Comment: The proposed emerging technology provisions are appropriate and should be adopted.

12. D-608

Comment: Provisions for commercial demonstration permits should be expanded to include pre-combustion coal cleaning technologies such as heavy media washing and chemically cleaning.

13. D-631

Comment: The entire concept of relaxed regulations for innovative technology demonstration is illegal. EPA's authority to subcategorze in this manner is allowable under section 111(j)(1)(A)(ii) only if the technology is likely to achieve emission reductions equal to or greater than the levels designated "best".

2.4 Emission Limits

2.4.1 60.42a Standard for Particulate Matter

General Comments on Particulates

1. D-274, D-289, D-329

Comment: The emission limit should be as strict as possible in order to insure public health and environmental quality.

Particulate Emission Limit

1. D-211, D-229, D-250, D-268, D-413, D-462, D-505, H-8

Comment: The proposed emission limit is correct or could possibly be stricter. This position was stated either without reason or based on the opinion that adequately demonstrated control technology can achieve the limit of 13ng/J (0.03 lb/10^6 Btu).

2. D-170, D-285, D-300, D-406, F-1y

Comment: The proposed emission limit is not tight enough. This position was stated either without reason or based on the opinion that adequately demonstrated control technology can achieve less than 13 ng/J (0.03 lb/10^6Btu).

3. D-167, D-168, D-205, D-215, D-216, D-218, D-219, D-223, D-224, D-227, D-231, D-234, D-256, D-259, D-266, D-271, D-315, D-322, D-325, D-330, D-368, D-369, D-370, D-380, D-397, D-398, D-399, D-403, D-404, D-410, D-418, D-433, D-437, D-438, D-446, D-447, D-448, D-451, D-458, D-460, D-461, D-463, D-464, D-466, D-467, D-471, D-473, D-475, D-476, D-481, D-482, D-483, D-485, D-486, D-488, D-489, D-490, D-491, D-519, D-585, D-642, D-682, F-1b, F-1g, F-1s, F-1x, F-2

Comment: The proposed emission limit is too strict. Many of these commenters favor the positions adopted by DOE and/or UARG. Many favor retention of the present standard of 0.1

lbs/10^6 Btu. Reasons stated were one or several of the following.

- The proposed standard is based on unproven technology and cannot be achieved.
- The proposed standard cannot be achieved consistently over the long term in a practical situation.
- "The standard would rule out a specific type of wet scrubber with unique environmentally acceptable characteristics that was designed for collecting fly ash from western coals and that was used in Northern Plains states as a device to remove SO_2. This procedure has enabled the consumption of energy to be reduced by accomplishing two pollution-control jobs in one step."
- The data are not sufficient to state scrubbing would not increase particulate emissions.
- A standard of 0.05 lb/10^6 Btu would allow scrubbers.
- A performance/acceptance test is not a true indication of everyday performance.
- The standard entirely precludes the use of wet particulate matter scrubbers.
- The only possible control technology (baghouse) is unproven on large utilities.
- The standard unjustifiably discriminates against the electrostatic precipitator.
- The proposed standard is highly inflationary.
- The benefit versus cost of the standard cannot be justified.
- Requirements should be set for health and environmental protection, not on highly expensive new technology.
- Reason unstated.

4. D-217, D-253

Comment: The proposed limit is unjustified for typical grades of fuel oil. In order for fuel oil to be exempt from using controls an ash content of 0.015 percent by weight would be required. If 0.02 percent by weight fuel oil were used, controls would be necessary for removal of only 0.005 percent by weight of the fuel oil.

5. D-156, D-262, D-265, D-277, D-371, D-373, D-401, D-417, D-449, D-477, D-574, D-621, F-1w, H-10

Comment: The emission limit should not be as strict as proposed. Several values ranging from 0.05 lbs to 0.08 lbs/10^6 Btu were proposed. This position was stated either without reason or to allow the use of electrostatic precipitators as one of the control options.

6. D-153, D-442, D-458

Comment: Does EPA include particulates entrained from a wet scrubber as part of the allowable emissions, or are they exempt?

7. D-120

Comment: Favor the standard but the emission limit is unfair to solid fuels and encourages coal liquefaction which is more costly, energy intensive and inefficient.

- Standard seems to encourage use of oil.
- EPA should consider fuel mixtures for these situations.

8. D-153

Comment: The standard does not provide for soot blowing.

9. D-369

Comment: Sections 60.42(a)(1),(2),(3) and 60.46a(a) are confusing. Why have mandatory percentage reduction and not enforce it?

10. D-313

Comment: The proposed standard is not strict enough. The California South Coast Air Quality Monitoring District requires 0.018 lbs/10^6 Btu.

11. D-231

Comment: The standard for particulates "ignores the extreme paucity of precipitator and scrubber data for lignite fueled power plants in Texas. On the same page the NO_x Standard (last paragraph) discussion uses the same argument for retaining the current lignite NO_x standard."

12. D-440

Comment: No credit is given for ash removal prior to combustion. Suggest credit be made in paragraph 60.42a.

13. D-468

Comment: The standard should be rewritten to measure allowable emissions in terms of mass of particulates per megawatt hours of output. This will create an incentive for increased combustion efficiency.

14. D-491

Comment: Bypass loops in conjunction with rapid switching dampers are necessary and should be provided to prevent any sudden reductions in boiler load level caused by fabric blinding that might affect system reliability. Bypass would allow boiler load levels to be maintained until safe reductions could be made, consistent with local and network power needs and proper emergency shutdown procedures. Bypass may also be necessary to protect boiler components and the baghouse itself.

15. D-627

Comment: The present NSPS for particulates provides a safety factor of around 35 for public health, when maximum ground-level concentrations resulting from a 500 MW plant are compared with NAAQS. There is no advantage in increasing this margin by the proposed reduction in allowable particulate levels. Ambient concentrations will not be reduced because with the reduced emission rates, plants up to 16 times greater (8000 MW) can be built under PSD standards.

16. D-631

Comment: The particulate emission limit should be 0.01 lbs per million Btu with 99.5% reduction required. Technology to achieve this has been adequately demonstrated.

Best System of Emission Reduction for Particulates

1. D-168, D-224, D-238, D-267

Comment: Control technology for particulates has not been demonstrated to the level required by the standard. No specific reasons stated.

2. D-168, D-216, D-227, D-231, D-237, D-250, D-256, D-259, D-262, D-300, D-315, D-320, D-322, D-141, D-426, D-444, D-458, D-491

Comment: Control technology for baghouses has not been demonstrated to the level required by the standard, particularly on large utilities. No specific reasons stated.

3. D-132, D-145, D-156, D-167, D-233, D-347, D-370, D-467, D-519, D-523, D-642, D-657

Comment: Control technology for baghouses has not been adequately demonstrated on large units. One or several of the following reasons were stated:

- No data are available on long-term life of bags.
- The problem of start-up temperatures was not adequately analyzed.
- The possibility of bypass during start-up and process upsets was not adequately addressed.
- Maintenance costs on large units were not properly assessed.
- Of 8 baghouses cited, 4 lacked data on type of filtration, air-to-cloth ratio, cleaning method, and/or pressure drop. Only 2 were on utility boilers. Only 3 are reverse air cleaned. Only 4 clean entire system. Only 2 burn pulverized coal. None operate on full size systems (100-1000 MWe).

4. D-153, D-247, D-263, D-274

Comment: The use of baghouses versus the sulfur content of the coal has not been sufficiently analyzed.

5. D-223, D-400

Comment: Section 111(b) of the Clean Air Act prohibits requiring any particular control system. The proposed standard is a de facto requirement to use a baghouse.

6. D-145

Comment: It is not clear whether baghouses can be operated properly on peaking units.

7. D-369

Comment: On page 17 of background document #10 listed in the preamble to the proposed standards, it is stated that several fabric filter manufacturers refused to guarantee meeting a limit of 0.03 $lb/10^6$ Btu. However, EPA has proposed such a limit.

8. D-268

Comment: Several fabric filter manufacturers will give written guarantees of 0.004 $lbs/10^6$ Btu at a price of $100 per KW installed capacity. Therefore, EPA has not proposed a strict enough limit.

9. D-145, D-205, D-227, D-464, D-467, D-491, D-519, F-1u

Comment: Control technology for ESPs has not been demonstrated to the level required by the standard, particularly for long term consistent operation or for large pulverized-coal-fired generating units.

- Of 21 tests, key data (recently conditioned, design values, coal types (sodium content)) were missing on nine.
- In one case (Centralia 2) the ESP was actually 2 in series.

10. D-156, D-247, D-265, D-397, D-461

Comment: The ESP should not be precluded from use with low sulfur coal. No specific reason was stated.

11. D-369, D-491

Comment: It is felt that EPA's tests on ESPs were done under ideal conditions. Under practical operation much larger collection areas would have to be used to guarantee meeting the standard. This would make the ESP uneconomical.

12. D-223

Comment: No mention is made of manufacturer's warranties, guarantees, etc. The user is held responsible.

13. D-253

Comment: No mention is made regarding whether or not EPA evaluated the extent to which particulate removal techniques are being used on low sulfur fuel oil fired burners. Nor was mention made of the possibility of achieving the proposed standard using low ash fuel alone.

14. D-413

Comment: Estimates for ESP size are underestimated. Suggest re-evaluation of cost/benefit based on minimum ESP of 450-500 ft^2/1000 ACFM (on 3.5% sulfur coal).

15. D-421, D-491

Comment: The particulate limit precludes the use of two-stage scrubbing as an effective control. EPA has effectively eliminated particulate scrubbing as an option for particulate control without adequately examining the costs, the non-air quality environmental impacts, and the energy requirements associated with particulate scrubbing in conjunction with SO_2 scrubbing. Based on the advantages and on the absence of an adequate analysis by EPA as justification for precluding particulate scrubbing, the revised particulate NSPS should be set at a level that would allow the use of particulate scrubbing.

16. D-455

Comment: "There are precipitators which on any day will meet the proposed 0.03 lb/10^6 Btu emissions standard. However, precipitator performance can deteriorate rapidly because of many reasons such as broken wires, control failures, fuel variability, etc. In my opinion, long-term precipitator reliability is the basic question if total emissions are to be controlled. I would recommend a gradual reduction, over a period of several years, of the present 0.1 $lb/10^6$ Btu emission standard so that design experience can be translated into workable solutions at minimal expense."

17. D-491

Comment: EPA states that it considers SCA values of 650 to 1000 ft^2/1000 ACFM to be reasonable for hot-side and cold-side ESPs, respectively, considering such factors as cost and energy. However, EPA has analyzed the cost of ESPs with SCA values of only 650 ft^2/1000 ACFM for a cold-side ESP. Thus, EPA has provided no support for its conclusion that ESPs of 650 SCA for hot-side ESPs and 1000 SCA for cold-side ESPs can achieve the proposed standard at reasonable costs.

18. D-491

Comment: EPA has provided no information of the accuracy and overall precision of Methods 5 and 17 or on the reliability of continuous opacity monitors. Information on the accuracy and precision of the designated methods when used on electric utility steam generating units at the 0.03 lb/MBtu level must be available before any conclusions can be drawn concerning the validity of the test results cited by EPA as support for the proposed NSPS and any tests made to determine compliance with the NSPS ultimately promulgated.

19. D-609

Comment: The adoption by EPA of NSPS less stringent than those which one of the nation's largest utilities has agreed can be met would be nothing short of irresponsible. Enclosed a Stipulation re BACT from Pacific Gas and Electric Company for proposed Fossil 1 and 2 power plant. BACT is defined as:

- SO_2 - 95% removal, 24 hr. average
- PM - 0.003 gr/scf
- NO_x - 0.45 lb/mmBtu (possibly as low as 0.034 lb/mmBtu)

20. D-631

Comment: EPA has overstated the costs of particulate controls. Both the proposed EPA standard and the EDF/NRDC proposal can be achieved at reasonable costs. Therefore, high cost is not a valid criticism of a stricter standard.

21. D-631

Comment: Adequately demonstrated control technology exists which has achieved emission limits of well below 0.01 lbs/10^6 Btu. This includes both fabric filters and ESP's operating on large units.

22. D-631

Comment: The use of flue gas conditioning by the addition of sulfur trioxide, ammonia, or triethylamine will significantly improve ESP performance on some coals. This will allow the use ofESP's to a greater extent than implied by the background documentation.

Adequacy of the Particulate Data Base

1. D-234

Comment: Insufficient data were presented to conclude that baghouses are demonstrated.

2. D-252

Comment: EPA neglected to state an opinion on the efficiency of the 350 MW unit which recently began operation.

3. D-219, D-483, D-491, F-1b

Comment: EPA's data base is not adequate enough to support the proposed standard for the following reasons:

- Only 44 percent of the EPA tests on control devices met the standard (75 percent for baghouses, 43 percent for ESP and 14 percent for scrubbers)
- Nine out of 21 ESP tests showing compliance does not constitute demonstrated technology over an extended period.
- Of the eight baghouse tests, six were on stoker-fired boilers and results were not transferable to pulverized units. Only one of two tests on pulverized units was in compliance and this was a small 44 MW unit. The standard should be based on factual, demonstrated data, not unsupported opinions.
- Critical pre-test information necessary to evaluate and interpret the performance of particulate control systems has not been included in the EPA data base.
- EPA's background information contains virtually no information on the cost-effectiveness of the proposed particulate NSPS.
- EPA's data base is too small and incomplete to provide sufficient statistical support for the proposed particulate NSPS.
- EPA's data base, comprised of results from a very limited number of intermittent performance/acceptance and compliance

tests, does not represent the performance of particulate control systems during day-to-day operation, including normal variations caused by such occurrences as soot blowing and load fluctuations.

4. D-369

Comment: The data and information used for determining control technology performance for both baghouses and ESPs is highly questionable. Background document EPA-450/2-78-006a shows the following:

- Only 5 of 21 units listed in Table 4-2 met the proposed standard.
- Three of the nine "best" units shown in Figure 4-14 could not meet proposed standard.
- In Table 4-5, two of eight units with baghouses could not meet proposed standard and largest tested was 44 MW.
- In total, only 9 of 21 units met the proposed standard.

5. D-317

Comment: In EPA's background information on scrubber particulate collection efficiency it is stated (Table S-3) that Duquesne Lighting's Phillips and Elrama plants achieve from 0.02 to 0.07 $lbs/10^6$ Btu. EPA fails to point out that the equipment used in obtaining that data was a heated probe with a glass wool collection device. The method used was not EPA Method 5. As a result, the test only represents collection of dust with no sulfates accounted for. However, recent Method 5 tests on these units, using similar coal, indicate that approximately one-third of the total particulate leaving the scrubber system

(0.03 lbs/10^6 Btu) is measured as sulfates. Thus even if the coal is completely flyash free or 100 percent of the flyash is removed, a residual of 0.03 lbs/10^6 Btu of sulfate particulates would be emitted. Thus, there is little chance that the particulate standard can be met in day-to-day operation.

6. D-443

Comment: EPA has failed to conduct sufficient analyses of particulate control on oil and gas units to establish a proper foundation for such a strict standard.

7. D-461

Comment: The use of specific collecting area (SCA) as the sole determinant of ESP efficiency is wrong. Other parameters include: electrical sectionalization, size and number of transformer and rectifiers sets, velocity, residence time, sodium content, ash char, type and number of rappers, design of high volts and ground electrodes, temperature, dew point and moisture content of gas, uniformity of gas flow, and particle size distribution. Seeding may increase particle sizes.

8. D-463

Comment: The effect of high altitude locations on baghouse air-to-cloth ratios was not assessed.

9. D-471

Comment: Montana Storm Units 1 and 2 were designed to meet 0.05 $lb/10^6$ Btu with a factor of safety. EPA results quoted were acceptance test results and do not reflect continuous operation or operation under load changes. The only way 0.05 $lb/10^6$ Btu was met was with significant overdesign. This will be true for the 0.03 standard also.

10. D-167

Comment: The EPA test on Iowa Public Service's George Neal Unit #3, which was used in the decision process, was ruled invalid by the Iowa Department of Environmental Quality. No explanation given.

11. D-491

Comment: EPA's record contains no data on the ability of lignite-fired boilers to achieve the proposed standard and no reliable data on the ability of oil-fired boilers to achieve the standard.

12. D-491

Comment: Until sufficient data becomes available to support a rational conclusion concerning the effects of NO_x and SO_2 controls on particulate emissions, EPA does not have an adequate basis for establishing a standard for particulate emissions to be measured after FGD systems.

13. D-631

Comment: The particulate emissions test data as well as the cost estimates which have been used to support the proposed revision are seriously outdated and thus fail to include a great deal of recent information which demonstrates the ability of particulate control systems on utility generating units to achieve significantly greater emission reductions at reduced costs than those projected by EPA. Specific examples of background document deficiencies are cited.

14. F-1u

Comment: EPA's data base is too small and incomplete; it does not include critical information on control-equipment design and operating parameters, fuel characteristics, and operating characteristics of the generating unit.

- Overall cost effectiveness of proposed particulate NSPS
- Potential effects of proposed NSPS for NO_x and SO_2 on proposed particulate NSPS
- Data base on baghouses not representative of site and type of generating units that will be subject to particulate NSPS
- Ability of test methods to measure accurately and precisely the small mass of particulate matter necessary to determine compliance.

Averaging Time for Particulates

1. D-461

Comment: 24-hour average not justified by EPA on technical or economic basis.

Particulate Control in the Presence of SO_2 and/or NO_x

1. D-168, D-219, D-325, D-491

Comment: Control technology for particulates has not been adequately demonstrated in light of possible interactions and synergistic effects from SO_2, NO_x and/or scrubbing chemicals. Reasons cited were:

- particulate carry over from scrubber
- difficulty of locating baghouse of ESP downstream of scrubber
- dewpoint and corrosion problems with multiple systems
- advantages of using calcium oxide in place of limestone in western units
- added energy required to compensate for mixed systems
- during load change and low load, excess air control is difficult and excess air (for NO_x control) may cause high particulate emissions. NO_x is difficult to control at low load and low excess air due to flame instability.

2. D-627

Comment: Scrubbers probably cannot be used for removal of both particulate and SO_2. Scrubbers often generate particulates and complete removal of this carry-over is not possible in a reasonable scale.

3. D-631

Comment: UARG has not adequately demonstrated that acid mist is an insurmountable problem. Technology to control this problem probably exists or should be expected within a reasonable time.

Opacity Standard for Particulates

1. D-256

Comment: The proposed 10 percent standard for opacity is not based on proven technology. Current 20 percent standard should be retained.

2. D-369

Comment: Under typical operating conditions, natural deterioration of ESPs would make achievement of 20 percent opacity questionable.

3. D-277

Comment: Opacity values should be correlated with particulate emission values during on-site testing.

4. D-256

Comment: Sections 60.42a(b) and 60.49a(e), should be changed to ensure that overlapping six minute periods are not considered an opacity violation. Also, allowances should be made for emissions instability during rapid load changes.

5. D-231

Comment: The standard should reiterate that states have the right to set more stringent opacity standards under 40 CFR 50.2(d).

6. D-455

Comment: EPA has not adequately addressed the matter of sulfuric acid (H_2SO_4) mist emissions from scrubbers on boilers firing high sulfur coal. It is my understanding that EPA has taken data on such units and that the levels of H_2SO_4 are rather high. It seems obvious that such a unit will have a plume of H_2SO_4 mist and that there would be difficulty in complying with the opacity regulation. To fully evaluate the environmental impact of scrubbers, the increased H_2SO_4 emissions caused by the burning of high sulfur coal should be evaluated with respect to the reduction in SO_2 emissions with scrubbers.

7. D-486

Comment: The allowed opacity excursion to 27 percent gives the impression of accuracy that does not exist.

8. D-631

Comment: It makes no sense to propose a standard which is one-third of the current emission limit and fail to revise the opacity standard at the same time. The use of 20 percent opacity as an enforcement device is virtually useless. The standard should be 5 percent or lower.

9. F-2

Comment: Wet scrubbers (which will be required for SO_2 control) should be exempt from the opacity standard because the addition of limestone to the circulating fluid renders them vulnerable to particulate re-entrainment and thus possible violations. The 20 percent limit has not been met by four of the company's five wet scrubbers.

2.4.2-60.43a Standard for Sulfur Dioxide

Sulfur Dioxide Emission Limit

1. D-82, D-87, D-90, D-145, D-147, D-156, D-167, D-194, D-215, D-216, D-218, D-219, D-223, D-224, D-225, D-227, D-231, D-232, D-234, D-238, D-242, D-244, D-250, D-251, D-254, D-256, D-257, D-261, D-263, D-265, D-266, D-270, D-272, D-274, D-276, D-277, D-288, D-289, D-294, D-300, D-304, D-305, D-306, D-307, D-308, D-309, D-310, D-311, D-312, D-315, D-317, D-319, D-320, D-321, D-322, D-325, D-329, D-330, D-332, D-333, D-334, D-335, D-336, D-337, D-339, D-340, D-345, D-357, D-361, D-366, D-367, D-368, D-370, D-371, D-373, D-380, D-397, D-398, D-403, D-404, D-405, D-409, D-410, D-414, D-415, D-417, D-418, D-421, D-423, D-425, D-426, D-427, D-429, D-433, D-435, D-437, D-438, D-440, D-442, D-445, D-446, D-447, D-448, D-449, D-450, D-451, D-452, D-457, D-458, D-459, D-460, D-461, D-463, D-464, D-467, D-468, D-469, D-471, D-473, D-475, D-476, D-477, D-478, D-481, D-482, D-483, D-488, D-489, D-490, D-491, D-498, D-508, D-514, D-516, D-519, D-523, D-531, D-537, D-538, D-540, D-541, D-542, D-545, D-547, D-548, D-549, D-552, D-556, D-558, D-561, D-571, D-590, D-610, D-612, D-613, D-614, D-616, D-620, D-621, D-628, D-635, D-639, D-642, D-643, D-648, D-651, D-657, D-678, D-683, D-684, D-694, F-1b, F-1d, F-1s, F-1u, F-1w, F-1x, F-1y, H-10, H-13

Comment: EPA should adopt the partial scrubbing (sliding scale) proposals of DOE, UARG, or similar plan. These responses had various reasons for proposing the sliding scale such as western vs. eastern coal, technology, less sludge, cost/benefit, etc., but all are characterized by explicit support of a sliding scale.

2. D-1, D-2, D-7, D-72, D-102, D-115, D-132, D-237, D-239, D-247, D-286, D-382, D-399, D-400, D-521, D-539, D-579, D-627, D-673, D-733, F-1e, F-1g, F-1u, F-1x, F-2

Comment: EPA should not promulgate a full scrubbing regulation. Such a regulation is inflation-causing, not necessary to protect air quality, too restrictive, etc. None of these comments offered an alternative standard.

3. D-27, D-28, D-32, D-41, D-52, D-67, D-114, D-284, D-407, D-466, D-583, F-1q

Comment: Full scrubbing discriminates against western coal. No explicit alternative is proposed.

4. D-157, D-175 (1.2 lb/10^6 Btu), D-212, D-747 (0.4 lb/10^6 Btu), D-232 (0.9 lb/10^6 Btu), D-262 (0.5 lb/10^6 Btu), D-271, D-401 (0.8 lb/10^6 Btu), D-697 (0.2 lb/10^6 Btu), F-1i

Comment: A less stringent emission limit should be adopted. (Values suggested are shown in parentheses.)

5. D-33, D-70, D-74, D-76, D-95, D-103, D-107, D-110, D-130, D-131, D-157, D-169, D-172, D-174, D-194, D-195, D-202, D-211, D-229, D-230, D-243, D-245, D-246, D-282, D-285, D-327, D-342, D-350, D-351, D-352, D-355, D-359, D-363, D-364, D-372, D-392, D-413, D-416, D-444, D-480, D-505, D-510, D-518, D-522, D-567, D-568, D-624, D-626, D-697, D-721, D-723, D-729, D-730, F-1c, F-1i, F-1n, F-1t, F-1o, H-8

Comment: The standard as proposed should be adopted on the basis of health effects, reducing PSD increments, intent of Congress, etc.

6. D-44, D-46, D-48, D-49, D-57, D-60, D-61, D-69, D-71, D-75, D-77, D-86, D-91, D-92, D-93, D-126, D-128, D-133, D-135, D-139, D-141, D-196, D-207, D-323, D-462, D-569, D-688, F-1n

Comment: The standard as proposed should be adopted but old plants should also be included in NSPS

7. D-6, D-8, D-9, D-10, D-63, D-78a, D-78b, D-79, D-83, D-84, D-85, D-92, D-94, D-97, D-98, D-99, D-101, D-104, D-105, D-106, D-107, D-108, D-112, D-116, D-117, D-118, D-119, D-121, D-123, D-125, D-129, D-130, D-136, D-137, D-140, D-142, D-143, D-144, D-146, D-148, D-149, D-151, D-154, D-155, D-157, D-161, D-162, D-166, D-170, D-172, D-173, D-174, D-176, D-177, D-178, D-180, D-182, D-183, D-184, D-185, D-186, D-187, D-188, D-190, D-192, D-194, D-197, D-198, D-199, D-200, D-201, D-202, D-208, D-209, D-213, D-220, D-221, D-226, D-229, D-235, D-236, D-240, D-243, D-249, D-264, D-268, D-273, D-275, D-278, D-280, D-293, D-313, D-324, D-327, D-331, D-350, D-351, D-352, D-353, D-354, D-355, D-358, D-359, D-360, D-362, D-363, D-365, D-372, D-374, D-375, D-377, D-378, D-379, D-381, D-384, D-385, D-386, D-387, D-388, D-389, D-390, D-391, D-393, D-394, D-395, D-396, D-406, D-411, D-428, D-434, D-441, D-456, D-492, D-493, D-494, D-495, D-496, D-497, D-499, D-500, D-501, D-502, D-503, D-504, D-506, D-507, D-513, D-517, D-524, D-525, D-551,

D-564, D-565, D-566, D-569, D-570, D-576, D-577, D-601, D-623, D-631, D-645, D-646, D-659, D-663, D-666, D-675, D-688, D-691, D-703, D-704, D-705, D-706, D-708, D-709, D-710, D-711, D-712, D-713, D-714, D-715, D-717, D-718, D-719, D-720, D-722, D-724, D-728, D-738, D-749, D-750, F-1i, F-1n, F-1t, H-11

Comment: A more stringent emission level should be adopted. The Japanese experience supports this. Removal efficiencies of 90 percent and 93 percent can be achieved and are suggested. The intent of Congress and PSD increment reductions support this approach.

8. D-72, D-335

Comment: Utilities with current low-sulfur coal contracts should be exempt for the life of the contract.

9. D-443, D-475

Comment: The proposed SO_2 removal requirement should be limited to coal-fired units only because:

- few, if any, non-coal fired units will be built
- they can be evaluated on a case-by-case basis under PSD
- very little effort was made to justify the new standard for liquid and gaseous fuels.

10. D-467

Comment: Section 60.43a(b) states that even during the three days per month in which the 85 percent reduction is not required, SO_2 must be reduced by 75 percent "at all times". The term "at all times" requires clarification since it is somewhat in conflict with the 24-hour averaging concept. It is recommended that this subsection be rewritten to clearly indicate that the 75 percent removal is to be averaged over at least a 24-hour period.

11. D-468

Comment: The standard should be rewritten to measure allowable emissions in terms of mass of SO_2 per megawatt hours of output. This will create an incentive for increased combustion efficiency.

12. D-488

Comment: It is recommended that EPA provide a variance for mine-run fuel to allow reporting of percent removal on a monthly average and compliance determined on a basis of emission of 1.2 $lb/10^6$ Btu or lower.

13. D-175, D-644

Comment: The standard should not dictate method for achieving low emissions. This amounts to a control of the marketplace and discriminates against low sulfur coal. The standard should give freedom of choice on how to comply.

14. D-631

Comment: The law and its legislative history require EPA to set a uniform nationwide percentage reduction. Promulgation of any "sliding scale" would be illegal, whether done directly or through EPA's authority to subcategorize.

15. D-491

Comment: In view of the limited experience with reliable FGD control on high sulfur coal, the emission limitation in the NSPS should not be lowered below 1.2 lbs/MBtu for this type of coal.

16. D-491

Comment: All of the economic modeling performed to date by ICF and NERA show that none of the proposed alternatives will reduce SO_2 emissions substantially more than others. This increases the importance of cost, environmental and energy impacts in the standard development. The UARG sliding scale is less costly, uses less oil, and produces less sludge. Therefore, it should be adopted.

17. D-631

Comment: The 3-day-per-month exemption for percent reduction should not be allowed since scrubbers are reliable and do not need exemptions.

18. D-631

Comment: Establishing an emission floor for SO_2 is clearly illegal since it is the same as a sliding scale.

19. D-554

Comment: Western bituminous coal should not be exempt because of severe economic impacts created on the Appalachian bituminous coal region.

20. D-536

Comment: The SO_2 standards proposed by EPA, DOE or UARG should not be adopted. All of these are too costly. No alternate given.

21. D-551

Comment: Since the sulfur and other mineral content of coals vary from one region to the next, standards of emissions should be set in parts/million, rather than as a percentage of sulfur to be removed.

22. F-1s

Comment: The argument that maximum SO_2 control would support local economies through use of local coal is invalid and cannot be supported as cost effective. Arguments of the Sierra Club and Red Mesa Chapters of the Navajo National lawsuit calling for maximum control of SO_2 regardless of sulfur content of coal are based upon the premise that there should be regulation simply for regulation's sake and do not reflect the cost/benefit approach mandated in the 1977 Clean Air Act amendments. Requirements differ throughout the nation and a uniform standard is neither logical nor efficient.

23. D-751, D-753, D-755, D-756

Comment: An emission limit of < 1.2 lb $SO_2/10^6$ Btu (as low as 0.55) with 90% removal will preclude the use of: 57% of Iowa coal, 74% of Illinois coal, 89% of Indiana coal, 100%

of Western Kentucky coal, 100% of Ohio coal, and 86% of Northern West Virginia coal. (Data is submitted with D-756.)

24. H-17

Comment: The Department of Energy recommends a flexible approach to SO_2 ceilings/floors and percent reduction, giving industry the option of complying with daily or monthly standards.

25. H-19

Comment: Since new power plants will be built, there will be an increase in emissions, regardless of the controls used. The Department of Agriculture favors a NSPS that will employ the maximum use of full emissions control while fairly considering the effects on economics, energy, and the benefits to the environment while minimizing the present atmospheric loading of sulfates.

Best System of Emission Reduction for Sulfur Dioxide

1. D-120, D-152, D-343

Comment: Technology exists to remove >90 percent of sulfur dioxide and should be considered.

2. D-157, D-176, D-178, D-350, D-355, D-357, D-626, D-631, D-633, F-1c

Comment: Technology exists to remove greater than 90 percent of sulfur dioxide as demonstrated by the Japanese experience.

3. D-145, D-175, D-210, D-233, D-467, D-735

Comment: Equipment to meet the SO_2 standard is not available

- limited experience
- capital, operating, and maintenance costs
- high risk equipment

4. D-168, D-216, D-244

Comment: Gross overdesign is required on large units; current efficiencies are based on small units.

5. D-252

Comment: The availability of scrubbers was not assessed sufficiently.

6. D-231

Comment: Regarding FGD availability; object to EPA being able to specify what "minimal amount of spinning reserve" must be maintained.

7. D-247, D-330, F-1s, F-2

Comment: Concerned about de facto elimination of dry scrubbing.

- 10 percent lower cost
- 10 percent lower total plant water requirements
- sludge handling simplified

8. D-246

Comment: New units have solved problems of corrosion, plugging, etc.

9. D-347

Comment: Cold end corrosion and scaling maintenance problems.

10. D-325

Comment: Interactions between controls have not been demonstrated.

11. D-14, D-30

Comment: Support coal cleaning.

12. D-418, D-491, D-519

Comment: The Japanese experience does not support the standard because of the following possible differences:

- the degree of closed loop versus open loop operation
- the impact of trace contaminants in oil and coal on closed loop operation
- the impact of different inlet SO_2 concentrations
- SO_2 uptake per volume of absorbent liquid
- the extent to which Japanese oxidize to gypsum and thus provide seed crystals for recycle to control scaling and produce a saleable end product instead of sludge
- the extent to which Japanese are able to perform routine maintenance during nighttime low load operations

- the impact of the Japanese continuous coal blending on the efficiency data
- only 5 FGD operate on coal-fired plants (coal has chloride buildup problem which has scaling and corrosion effects)
- Japanese have much higher blowdown than allowable in U.S. (e.g. more open loop)
- market for gypsum reduces waste disposal problems
- no data in record comparing technology, economics, or costs for Japanese systems

13. D-442

Comment: There has been no successful application of an FGD system on Illinois coal which is very high in chloride content, creating additional problems in scrubbing.

14. D-464

Comment: Based on one year of operating experience with FGD, it is concluded that the technology required to meet the standard has not been adequately demonstrated on Indiana-Illinois Basin high sulfur coal.

15. D-218

Comment: Scrubbers have a poor record on coals mined in the southern part of the middle Atlantic region.

16. H-12

Comment: Provides additional analyses of the proposed standard alternatives. Conclusions point out the following:

- sliding scales produce 3-4% greater emissions at cost savings of up to $800 million in 1990 and $1.5 billion in 1995

- low ceiling options are more cost effective than high ceiling cases
- sharp increase in incremental costs of SO_2 removal in going from sliding scale to full control
- EPA has not analyzed exposure and health effects
- utility oil consumption is higher under full control than sliding scales
- distribution of coal production and price is insensitive to the choice of performance standard

17. H-14

Comment: Preliminary results of a study of the economics of phased installation of FGD systems indicate overall savings on the order of 0.7 to 1 mills/kwh, compared to a single-step strategy. The phased strategy examined called for proceeding through four stages to scrub additional amounts of flue gas in 25 percent increments from year 0 to year 15. Eighty-five percent of the SO_2 would be removed from the flue gas by a scrubber with 90 percent design capability at an energy penalty of 1.6 percent of gross boiler output. Cost estimates are reported in 1978 dollars after escalation to 1983.

18. D-630

Comment: Coal blending can reduce but not eliminate sulfur variability.

19. D-632

Comment: Coal blending to meet a standard under a sliding scale would cost $0.94/ton at the Pawnee Power Station in

Colorado - less than 1/7 the cost ($6.92/ton) to install a wet scrubber.

20. D-519

Comment: Equipment guarantees quoted by EPA do not state averaging time.

21. D-519

Comment: Sodium carbonate scrubbing, dual alkali scrubbing, magnesium oxide scrubbing, Wellman-Lord, and spray dryer/fabric filter technologies are not demonstrated or not universally applicable due to unique cost and/or unique process considerations.

22. H-13

Comment: Use of injection of additives such as adipic acid in the scrubber slurry as presented in the December 8, 1978, Federal Register is not seen as meeting the definition of best technological system which has been adequately demonstrated. No test conditions or operating experience with this control technique are discussed. Therefore, it should not be further considered by EPA until it has been adequately demonstrated.

23. D-519

Comment: Stack liner problems:

- takes issue with findings that liner problems can be solved by using more expensive materials - Agency doesn't have evidence to support this or statements of manufacturer guarantees. Cites numerous cases of corrosion.

24. D-491

Comment: Long-term reliability of closed-loop scrubber operation has not been demonstrated.

25. D-491

Comment: SO_2 control technology has not been adequately demonstrated for the following cases:

- continuous long-term operation on low sulfur coal with an open-loop control system
- continuous long-term operation on low sulfur coal with a closed-loop control system
- continuous long-term operation on high sulfur coal with a closed-loop control system

26. D-491

Comment: Proposed SO_2 standard was based on the most advanced technological system of control. This forecloses the development of competing scrubber and "front-end" technologies which are less advanced but have the potential for a better balance among costs, environmental and energy benefits.

27. D-631

Comment: The operational differences between Japanese and American scrubbers which result in the high efficiency and reliability of Japanese scrubbers include:

- attitude of plant operators
- skill of FGD system operators
- close government surveillance of power-plant emissions
- specific technical differences in the mode of scrubber operation.

Since all of the above are transferable to U.S. facilities, there is no reason why average efficiencies of 94% cannot be achieved.

28. D-519

Comment: Use of Mg^{++} to reduce scaling is not a proven technique. The examples used by EPA are inappropriate.

29. D-609

Comment: The adoption by EPA of NSPS less stringent than those which one of the nation's largest utilities has agreed can be met would be nothing short of irresponsible. (Enclosed a Stipulation re BACT from Pacific Gas and Electric Company for proposed Fossil 1 and 2 power plant which defines BACT as:

- SO_2 - 95 percent removal, 24 hour average
- PM - 0.003 gr/scf
- NO_x - 0.45 lb/mmBtu (possibly as low as 0.034 lb/mmBtu)

Adequacy of the Sulfur Dioxide Data Base

1. D-369

Comment: The following comments on the SO_2 data base are submitted:

- Bruce Mansfield No. 1 results have been misused; plant was operating at 50% load
- La Cygne "excellent" availability subject to pending repairs which have not been considered
- Question overall availability data
- Bruce Mansfield base loaded - new facilities will be dispatched to accomodate load
  - a) FGD reagent slurries will go off optimum pH under new load
  - b) see real problems with measurement and monitoring removal capability

2. D-371, D-373, D-449, D-575, D-610

Comment: Modeling does not adequately support the standard

- Large discrepancy between EPA and NERA
- NERA study shows Texas will pay 25% of national cost of full scrubbing
- In the detailed "further analysis" (Dec. 8, 1978, FR) report of the consultant we noted a critical error in the assumption used relative to sulfur content of Powder River coal. Using an assumption of 1 lb sulfur/million Btu's overstates the sulfur content by about 100 percent; and consequently, the removal costs would be vastly overstated as well.
- Submission of RTI report (D-610) showing reasons for discrepancies between ICF and NERA models. Favors ICF model but a NSPS of "0.55" or "full West/0.55 rest" as more favorable (cost/benefit) than either EPA, DOE or UARG.

3. D-397

Comment: Data does not justify 85% removal of sulfur dioxide.

4. D-397

Comment: Should not use data from demonstration units, nor spot or performance tests.

5. D-448

Comment: Should not justify standard on eastern versus western coal economic issues.

6. D-435

Comment: The economic impact of the proposed regulations is incomplete.

- independent assessment of impacts by modeling
- critical of linear programming approach--washes out geographic detail influencing individual power plant fuel options
- analyses of 4 sites on coal transportation

	Indianapolis	Louisville	Austin	Tampa
(1) daily avg., .2 lb floor EPA	7600/176/--	7600/165/--	3800/74/--	7600/189/--
(2) daily avg., .5 lb floor, fix bypass	3800/24/229	3800/24/46	3200/36/106	3800/24/236
(3) daily avg., .5 lb floor, variable bypass	6400/17/274	6400/17/91	6400/29/145	6400/17/282
(4) monthly avg., .54 lb floor, variable bypass, DOE	7000/16/366	7000/16/175	7000/27/221	7000/16/366

(5) monthly avg., sliding scale, variable bypass, UARG	8900/10/641	8900/10/450	9600/20/473	8900/10/641

Legend for table: emissions/sludge/cost saving \$(10^6)
(tons) (10^3 tons) over EPA (30 yrs, 500 MW, 8942 Btu/kWh)

7. D-450

Comment: Full scrubbing too costly with respect to benefits.

- cites NAS report indicating benefits of \$200/ton SO_2 removed; costs of \$1,184/ton SO_2 removed shows a large imbalance.

8. D-455

Comment: It is improper to evaluate the cost of the standard on the basis of gross cost or average cost per consumer. A more meaningful way would be to compare the incremental increase in the consumer cost with the incremental decrease in emissions. If emissions are not decreased by the effect of the regulations or are only decreased a small amount relative to the cost, then money is being wasted.

9. D-455

Comment: The continuous monitoring data from the Cane Run and Bruce Mansfield Power Plants which were used to determine scrubber removal capability is totally deficient.

10. D-458, D-491

Comment: EPA does not show that the present limited experience with non-lime/limestone technology can be used to justify the higher level of removal efficiency and availability reflected in the standard on a continuous basis. Extrapolation from test units to commercial scale is difficult.

11. D-461

Comment: The costs specified on page 43FR42163 are distorted. EPA states \$260 to \$1600/ton for low sulfur coal while industry estimates \$900 to \$2000/ton.

12. D-467

Comment: Experience has shown an 8-10% inflation rate for new facilities, not the EPA 5.5%.

13. D-459

Comment: The project to determine the percent SO_2 reduction data for the four FGD systems listed in Section 4.2.4 of the background supplement EPA-450/2-78-007a-1 was not of sound scientific design. This project proports to evaluate the probability distribution of FGD 24-hour average SO_2 removal efficiencies. It appears that fatal errors were made in the design and execution of this project. Specifically, there was the lack of uniformity in the sampling period, in continuous monitoring equipment, and in the sample points. Also, the results were biased by exclusion of some sampling data and the apparent selection of an extremely small number of FGD systems.

14. D-479

Comment: Control costs will depend on variables which are not known:

1) cost of coal transportation
2) labor increases
3) strip mine regulations
4) sulfur content and Btu value of different coals
5) capital cost estimates for control equipment
6) power plant capacity factor used
7) heat to power (Btu to MW) conversion efficiency value used
8) annualized control equipment cost:
    - depreciation
    - insurance
    - taxes
    - interest
    - operating and maintenance costs
9) growth estimates too low

15. D-483

Comment: Data base does not warrant optimistic assessment of levels of reliability and removal efficiencies of FGD.

16. D-485

Comment: Data base does not appear to correctly calculate cost of full scrubbing to the consumer.

17. D-485, D-682

Comment: Data base does not appear to substantiate the claim that proposed regulations will substantially reduce SO_2 emissions.

18. D-488

Comment: The EPA economic analysis assumes coal costs increase at 6.5% per year. Our system estimates 10 to 15%.

19. D-491

Comment: There are no EPA data which support the assumption that scrubbers are demonstrated at or near 90 percent reliability with one spare module.

20. D-491

Comment: The data base used for assessment of the lime/limestone FGD technology does not establish that such systems can attain the required levels of efficiency on a continuous basis.

21. D-491

Comment: No where do EPA's contractors relate the removal efficiencies cited for SO_2 to averaging times. In addition, no evidence is presented that high removal efficiencies can be achieved on a continuing basis without substantial and unproven changes to present FGD systems.

22. D-519

Comment: The following comments are submitted with respect to lime/limestone capability:

- In general EPA ignores Bechtel findings that an 85 percent standard will require further work with respect to chemistry, need for spare modules, etc.
- Green River has had poor availability contrary to EPA record
- Mojave scrubber is no longer working
- Four Corners no longer operating to control SO_2
- Mojave, Cholla, and Four Corners all operated with 200 ppm SO_2 input
- Cane Run #4 and Paddy's run use scarce carbide lime-atypical and costly
- St. Clair operated at unacceptably high excess air for continual operations.
- Bechtel stated that Shawnee results were under atypical operating conditions
- Phillips and Green River were never evaluated under continuous conditions.

23. D-512

Comment: Record substantiates the claim that the proposed regulation will have no major impact on emissions in 1990.

24. D-582

Comment: Power plant cost data are submitted with two comments. The commenter favors the sliding scale option.

- question the cost analyses that do not include the cost of replacing a scrubber after 20 years on a power plant with a 30 year plus life. (ICF material pg. 10, Dec. 12, 1978 hearing material)
- question the values used for "scrubber capital charge rate" in the same analyses. Assuming this is equivalent to "fixed charge rate", we would expect the value to be fetween 15-20 percent for investor owned utilities, and somewhat less for public utilities.

25. D-631

Comment: The result of EPA's modeling is only as good as the input data and model assumptions. Therefore the model results are totally inadequate since,

- the conclusions are largely determined by a single issue - the price of oil
- secondary effects on environment, energy and costs are neglected
- EPA's incorrect interpretation of the meaning of the phrase "taking into consideration costs".
- failure to recognize the sensitivity of small changes in input data to the overall results

26. D-611

Comment: The data which were obtained during the EPA continuous monitoring studies do not accurately characterize FGD performance variability due to the problems which were encountered during the studies and the resulting errors in the monitoring data. In addition, the 24-hour average efficiency data which EPA obtained during the monitoring studies cannot be assumed to be representative of long-term, steady-state FGD performance because:

- many of the systems produced only sporadic, short-term data
- one system was monitored during initial startup
- insufficient data were obtained during four of the five studies, which were included in EPA's statistical analysis, to characterize long-term FGD performance variability

- during the FGD monitoring study program, neither a diluent monitor accuracy test nor a combined system accuracy performance test was reported at any of the continuous monitoring sites

27. D-744, D-756

Comment: Inadequacies in the data base regarding the relationship of short-term and long-term scrubbing and the cost or feasibility of coal washing precludes consideration of a lower ceiling or higher removal efficiency requirement than proposed.

28. D-755

Comment: Apparently no assessment of the employment impacts of the proposed SO_2 standard has been made. Also, the environmental benefits have yet to be revealed on any basis other than aggregate national and regional emission quantities.

Averaging Time for Sulfur Dioxide

1. D-98, D-157, D-169, D-174, D-245, D-331, D-341, D-350, D-351, D-354, D-355, D-363, D-375, D-381, D-386, D-388, D-393, D-394, D-406, D-411, D-494, D-496, D-499, D-500, D-504, D-506, D-513, D-517, D-564, D-569, D-601, D-623, D-624, D-631, D-645, D-646, D-697, F-1i

Comment: Favors 24 hour averaging time

- 30 day average permits gross violations over short time periods
- averaging time will affect SIP plans for smelters which are based on short term averages
- easier enforcement
- no reason given

2. D-145, D-147, D-156, D-167, D-215, D-216, D-218, D-219, D-223, D-225, D-231, D-232, D-238, D-244, D-247, D-250, D-256, D-259, D-314, D-315, D-317, D-322, D-370, D-371, D-403, D-404, D-405, D-407, D-410, D-415, D-417, D-418, D-425, D-438, D-442, D-444, D-446, D-447, D-448, D-449, D-459, D-461, D-464, D-467, D-476, D-483, D-488, D-490, D-491, D-514, D-523, D-571, D-610, D-620, D-630, D-642, F-1q, F-1y, F-1aa, H-10, H-13

Comment: Favors 30 day averaging time

- coal variability
- reliability of continuous monitoring
- lack of data showing that 85% reduction on 24 hour average basis over extended periods is achievable
- irregularities of operation (load changes, etc.)

- reliability of scrubbers
- lime variability

3. D-440

Comment: Fuel treatment is based on 90-day averaging; therefore, SO_2 removal should be based on 90-day average.

4. D-482

Comment: Favors 3-hour averaging time to make the standard the same as PSD and NAAQS.

5. D-455

Comment: The SO_2 standard, as written, is unwieldy in regard to the calculations to determine 24-hour removal by the scrubber. It is ridiculous to have a 24-hour standard calculated against a quarterly fuel-cleaning credit with 3 days per month exemption. It would seem more reasonable to apply all standards and credits to a 30-day period with indication of compliance using analyzers and compliance testing using Method 6.

6. D-491

Comment: The data on which EPA bases its averaging time conclusions are not valid because the short term performance test data are not analyzed in a manner to permit such conclusions. Certification procedures were not always followed and portions of the data were excluded as a result of system failures.

7. D-744

Comment: Question the conclusion made regarding the relationship between short-term scrubber performance (24-hour average) and long-term scrubber performance (30-day average).

8. H-17

Comment: The Department of Energy recommends a flexible approach to SO_2 ceilings/floors and percent reduction, giving industry the option of complying with daily or monthly standards.

Sulfur Removal Credit

1. D-369

Comment: Does SO_2 removal start with crude oil at the well head or refined oil?

2. D-230

Comment: Concern is expressed over the failure to allow sulfur credits for "cleaning" and/or refining high sulfur crude oil.

3. D-321

Comment: No credit given to 10% to 40% sulfur in flyash from low sulfur western coal (depending on sodium in ash).

4. D-223

Comment: Supports credits for pulverizing, bottom ash and flyash.

5. D-259

Comment: Proposed standard does not say how credits for precleaning will be incorporated into continuous monitoring data.

6. D-490, D-485

Comment: Supports sulfur credits

7. D-467

Comment: The preamble states that rotary breakers or coarse screens will not be considered a fuel pretreatment. However, the House Report states that all processing steps performed on a material from its natural state should be taken into consideration.

8. D-488

Comment: The method for calculating percent removal by coal cleaning or ash interaction by using coal sampling prior to combustion will require approximately a 200 pound sample per hour per generating unit. This will require a very elaborate, expensive sampling system.

9. D-217

Comment: A mechanism should be provided to apply the refinery desulfurization credits to petroleum coke sold to utilities for fuel and to fuels from alternate energy sources such as tar sands or oil shale.

10. D-217

Comment: Although fuel oil pretreatment to remove sulfur can be credited toward the 85% reduction, the respondent desires that the process of fuel oil desulfurization at a refinery be specifically mentioned as an accepted method of fuel oil pretreatment.

11. D-217

Comment: The proposed formula for calculating SO_2 removal efficiency by fuel oil pretreatment "breaks down" in a number of common refinery situations, e.g., when fractionation, cracking or coking processes intervene between desulfurization and fuel oil blending. (An alternate formula is proposed.)

12. D-608

Comment: There should be a decision by the U.S. EPA relating to the emission factor to be used for SO_2 emissions when burning Western subbituminous coal from Colstrip County in Montana.

13. D-523

Comment: Credit is to be given for sulfur removal prior to coal use, yet the scale of credit appears inequitable; for instance, if 25 percent of the sulfur is removed by pretreatment, the control requirement for SO_2 is reduced by only 5 percent (43FR42173). There should be a more direct trade-off between sulfur removal in pretreatment and the present reduction requirement.

14. D-631

Comment: Supports sulfur credits for washing due to numerous side benefits,

- reduces coal variability
- reduces coal shipping costs
- reduces boiler and scrubber maintenance
- reduces sludge handling

2.4.3-60.44a Standard for Nitrogen Oxides

Nitrogen Oxides Emission Limit

1. D-132, D-145, D-156, D-167, D-168, D-205, D-216, D-218, D-219, D-223, D-224, D-231, D-232, D-234, D-238, D-250, D-263, D-271, D-287, D-300, D-301, D-315, D-320, D-322, D-325, D-330, D-347, D-369, D-370, D-380, D-397, D-401, D-410, D-417, D-421, D-425, D-426, D-433, D-438, D-446, D-447, D-448, D-449, D-451, D-458, D-460, D-461, D-464, D-467, D-471, D-473, D-475, D-476, D-477, D-481, D-483, D-489, D-491, D-519, D-611, D-642, F-1b, F-1g, F-1s, F-1u, F-1w, F-1x, F-1y.

Comment: The majority of the commentors were critical of the proposed limits on grounds of insufficient control technology demonstration (see next subsection). Additional, though less frequently mentioned, comments included insufficient health effects justification, retraining for new technology, and the discrimination against the use of subbituminous coal due to its stricter standard. All of the above comments either explicitly recommended no change to the current standard or made a strong criticism of the proposed standard.

2. D-238, D-370

Comment: These comments suggested a 0.6 lb/10^6 Btu Standard based on the inability of technology to achieve the proposed standard. In both cases, no specific fuel type was mentioned nor was an applicable technology mentioned. The commentors stated that a 0.5 lb/10^6 Btu standard had not been demonstrated on a continuous basis.

3. D-9, D-170, D-229, D-268, D-313, D-462, D-505, D-631, H-8

Comment: Either agreed with proposed standard or suggested more stringent standard as follows:

D-9 (0.1 ppm/hr)

D-170 (Stricter Controls)

D-229, D-462, D-505 (Agree with Standard)

D-268 (0.38 - 0.45 lb/10^6 Btu)

D-313 (0.018 lb/10^6 Btu)

D-631 (0.45 lb/10^6 Btu with requirement for facilities to accomodate the use of catalytic ammonia injection when that control technique is fully developed, e.g., potential of .02-.05 lb/10^6 Btu)

Most of these commentors felt that the record indicates a stricter standard is achievable. It was pointed out by several commentors that vendor guarantees to the California Air Resources Board indicate that a 0.45 lb/10^6 Btu is readily achievable. In addition, emissions of 0.34 lb/10^6 Btu in Japan by a U.S. vendor are reported as well as pilot results with ammonia injection.

4. D-366

Comment: NO_x standard should only apply to station complexes with a total of 4000 x 10^6 Btu/hr or greater.

5. D-438, D-448

Comment: Validity of formula for coal mixing not proven and not practical to implement.

6. D-468

Comment: Standard should be rewritten to measure allowable emissions in terms of mass of NO_x per megawatt hours of output. This will create an incentive for increased combustion efficiency.

7. D-488

Comment: Texas lignite should also be included in 0.8 $lb/10^6$ Btu requirement when burned in a slag tap furnace.

8. D-203

Comment: The equation at 43 FR 42176 should read:

$$PS_{NO_x} = (w(86) + x(130) + y(210) + z(260))/(w+x+y+z).$$

Best System of Emission Reduction for Nitrogen Oxides

1. D-145, D-153, D-168, D-205, D-219, D-224, D-232, D-234, D-238, D-263, D-271, D-300, D-301, D-315, D-322, D-370, D-404, D-409, D-418, D-426, D-442, D-455, D-461, D-463, D-491, D-519, D-611, D-642, F-1w

Comment: These comments explicitly reflected a feeling that there has been insufficient demonstration of the control technology (combustion modification). The principal concerns expressed were with respect to increases in boiler tube corrosion under low NO_x operation and increased slagging. The appropriateness of coupon testing was questioned and the fact that long term corrosion data are still being collected was cited as evidence of insufficient demonstration. Increased slagging due to a reducing atmosphere characteristic of staged combustion was the primary slagging concern. In addition, the regulation would not allow sufficient flexibility to increase excess air to reduce slagging since this would tend to raise NO_x levels.

2. D-132, D-156, D-167, D-168, D-218, D-250, D-287, D-320, D-322, D-330, D-347, D-370, D-400, D-410, D-433, D-437, D-442, D-444, D-449, D-451, D-491, D-519, D-611, F-1b, F-1g, F-1u, F-1x

Comment: These comments are with respect to the apparent monopoly on design by 1 or 2 manufacturers.

- Three of four boiler manufacturers have recommended that EPA not change the NO_x NSPS

- One boiler manufacturer meets standard due to its tangential fired boiler design
- A second boiler manufacturer has not achieved a 0.45 lb/10^6 Btu guarantee for one unit after 2 years of operation
- A third manufacturer has not brought low NO_x unit guaranteed to meet 0.45 lb/10^6 Btu on-line yet
- Boiler manufacturer guarantee not on continuous basis but on compliance test basis-big difference
- Justice Department has commented on implications for competition

3. D-320

Comment: This commentor claims San Juan facility could, at best, operate at 0.6 lb/10^6 Btu whereas it was designed to meet a 0.45 lb/10^6 Btu standard.

4. D-223

Comment: Standard should be function of boiler type.

5. D-369, F-1aa

Comment: Tables 6-2 and 6-9 of EPA 450/2-78/005a show boiler tube corrosion losses of 285-488 percent in certain test coupons. These losses are significant but are discounted by EPA.

6. D-271

Comment: Experience with tangentially fired boiler with overfire air burning sub-bituminous western coal resulted in excess slagging after 3 days of operation. (No other specifics are given as to operation.)

7. D-325, D-491, D-519, D-611

Comment: Interaction with other controls such as FGD and NO_x not demonstrated.

8. D-3, D-491, D-519, D-611

Comment: Reheat for scrubbing will increase NO_x emissions.

9. D-609, D-631

Comment: Additional control of NO_x, far beyond what EPA is currently contemplating, can be achieved at a very reasonable cost. As a minimum, California Air Resources Board has guarantees from two vendors for 0.45 $lb/10^6$ Btu (no coal type or averaging time specified). In addition CARB is specifying that a capability to use ammonia catalytic injection be incorporated in new plants. A Japanese coal-fired power plant (Isogo Power Station) has demonstrated removal efficiencies of 90 percent or NO_x emissions of 0.034 $lb/10^6$ Btu using a pilot ammonia catalytic injection system (no coal type or averaging time specified). Also, at least one Japanese boiler built by an American manufacturer operates at 0.34 $lb/10^6$ Btu.

10. D-156, D-491, D-519

Comment: EPA did not consider unit efficiency reduction along with boiler effects. Lower combustion temperatures with low-NO_x may reduce steam turbine inlet temperatures and thus overall electrical efficiency.

11. D-491, D-519

Comment: Question results of control technology improvements shown in record:

- Agree with EPA that expanded boiler size reduces NO_x. However, points out that (1) beyond a limit, steam temperature becomes depressed and unit loses turbine efficiency and (2) units designed for current NSPS already use this technique and little gain can be expected in future units.

- Gains indicated by EPA from staged combustion were demonstrated on older units. More modern units already achieve some of the effects of staged combustion.

- Overfire air does not appear to be a long range control due to concerns about potential adverse side effects attributed to it. EPA should address this fact.

- The record demonstrates that combined effects of combustion modification is less than the sum of each individual effect.

Adequacy of the Nitrogen Oxides Data Base

1. D-203

Comment: NO_x data for shale oil combustion is not available. More tests are needed.

2. D-145, D-491, D-519, D-611

Comment: Study needed to determine fuel-bound NO_x percentage of emissions. Bituminous coal about 23% higher in fuel bound nitrogen than subbituminous coal.

3. D-458

Comment: EPA data was collected with an uncertified continuous monitor at one boiler. This is hardly justification for all boilers on a continuous basis.

4. D-491, D-519, D-611

Comment: Question test information on record. Information was not complete with respect to: type of operating conditions (representative, long term, load, load follow, fuel type), reference method, number of tests/instance, time period covered, number rejected (and why), check for stratification, chemical analyses for reference 7, steady state or not, normalized using F-factor or fuel analysis, fuel samples used for F-factor.

5. D-491, D-519, D-611

Comment: EPA did not evaluate enough boilers subject to current NSPS standard.

- Survey indicates that no boiler subject to current NSPS can meet 0.6 lb/million Btu on a range of bituminous coals.

- Only two performance tests on two of five boilers subject to the current NSPS and burning bituminous coal met a 0.6 lb/million Btu standard.

6. D-491, D-519, D-611

Comment: Data base for evaluating continuous NO_x emissions was inadequate.

- Short term results can be run with atypical configurations. EPA admits some of its data reflect this mode of operation;

- Virtually no continous NO_x monitoring data exist on boilers subject to the current NSPS;

With respect to the Colstrip continuous monitoring data:

- Data used to set standard collected prior to shakedown. New data show results above proposed standard;

- Data only from a tangential boiler;

- Used only one subbituminous coal type;

- No load variation data or supportive performance test results used;

- Uncertified data.

Averaging Time for Nitrogen Oxides

1. D-223, D-232

Comment: Supported 30 day averaging as a minimum reasonable averaging time (no supporting documentation was given).

2. D-413, D-421, D-461, D-519, F-1u

Comment: Data presented does not support use of 24-hour averaging.

Relationship of Nitrogen Oxides with Other Pollutants

1. D-156, D-218, D-491, D-519, F-1a

Comment: Particulates may increase under the proposed NO_x standard.

2. D-491, D-519, D-611

Comment: CO increases due to low-NO_x operations.

- Table 6-3 of EPA 450/2-78/005a (NO_x Background Document) shows ten fold increase in CO as NO_x emissions are reduced.
- Even with tangentially fired boilers, data on Pages 6-14 and 6-15 shows five fold increase in CO.

Nitrogen Oxide Cost Analyses

1. D-491, D-519, D-611

Comment: Cost Analyses

- Scenario I (most likely) does not take into account EPA's own judgement that all boiler-types are not equally effective. In addition, costs for R&D, premiums on guarantees, maintenance and replacement power costs due to corrosion, risk due to accidents under low-NO_x conditions, reduced unit efficiency, and each boiler type/fuel combination have not been performed adequately.

- Scenario II ignores time and relative financial and technological base of manufacturers to develop new low NO_x systems (or burners). In addition, time delays could force one or both manufacturers out of the market. It is also suggested that the ratio of cost to net income from boiler sales would have shown a different result as to impact of burner development on one manufacturer.

- Scenario III assumptions are unjustified and ignore the fact that utilities would not risk buying a new tangential boiler design from a manufacturer who had never built or fully tested one before. This will tend to increase the anticompetitive effects of the regulations by driving boiler manufacturers out of the market.

2. D-491, D-519, D-611

Comment: Proposed standard may cause increase in use of subbituminous coal since 0.6 $lb/10^6$ Btu bituminous coal NO_x standard may not be achievable.

Nitrogen Oxide Safety Issues

1. D-491, D-519, D-611

Comment: Indication of flyash carbon carryover doubling in the low-NO_x mode has safety as well as efficiency and particulate emission implications.

2. D-491, D-519, D-611

Comment:

- No risk assessment made of continued low-NO_x operation. Tests were performed with trained test engineers over short time periods.
- Not enough margin of flexible operation (e.g., excess air).

2.5 Testing, Monitoring, and Reporting

2.5.1 - 60.46a Compliance Provisions

Compliance Testing

1. D-168, D-259, D-464, D-491

Comment: EPA must properly validate its test methods and provide information on the overall accuracy of those methods when used to measure particulate emissions from fossil-fuel-fired electric utility steam generating units at the 0.03 lb/10^6 Btu level.

2. D-631

Comment: Failure to require compliance testing for percent reduction of particulate is a direct violation of section 111 of the Clean Air Act. Adequate technology for such testing exists.

Startup, Shutdown and Emergency Bypass

1. D-223

Comment: No provisions are made for exemption of particulate during startup, shutdown and malfunction.

2. D-320, D-410, D-438, D-477, D-483, F-1y

Comment: The emergency bypass provisions should be more lenient. In addition,

- determination should be made on the basis of those units on line at the time of occurrence.
- cold starts for turbines should be exempt under these provisions

3. D-156, D-168, D-250, D-523

Comment: A more lenient emergency bypass provision is needed because:

- unreliable scrubbers will require it
- costs to meet present provisions are substantial
- impact of looser provisions on air quality is negligible.

4. D-253, D-488, D-491

Comment: Section 60.46a(d)(2) would require operating a FGD module until it is completely inoperable before it can be bypassed. This could cause major damage to it in some cases. It is recommended that the word "malfunctioning" be substituted for "totally inoperable" and malfunctioning defined as a reduced efficiency or capacity of a module.

5. D-415

Comment: The emergency bypass provisions should be guidelines rather than rigid rules.

6. D-523

Comment: One of the conditions for SO_2 bypass operations is to install a spare FGD module. There is an apparent contradiction in the size of unit requiring a spare module: the preamble cites > 125 MW heat input (43 FR 42159) and the proposed regulation states > 365 MW heat input (43 FR 42176).

7. D-491

Comment: Section 60.46a(d) should be clarified by changing the phrase "continue operation" to "be operated". This will allow a malfunctioning unit to be brought on line during an emergency or projected emergency as opposed to the current meaning which would only allow an on line unit to continue.

8. D-611

Comment: The proposed requirements of 40CFR60.47a(a) would allow alternative methods in place of a transmissiometer to assure that particulate control equipment is properly operated and maintained. The requirement for reporting in §60.49a(e), however, appears to preclude the use of other methods, such as monitoring particulate matter control equipment parameters. Since the single intent of opacity monitoring, _e.g_. 43FR42172, is to assure that particulate control equipment is properly operated and maintained, the alternative methods should not be foreclosed.

2.5.2 - 60.47a Emission Monitoring

General Comments on Emission Monitoring

1. D-206

Comment: Paragraphs 60.47a(a), (b), (c) and (d) should be reworded as follows: "The owner or operator of an affected facility shall install, calibrate, certify, maintain and operate...", if the intent is to require individual on-stack certification of continuous monitors as presently required under 40CFR60, Subpart D. Subparagraphs (b), (c), and (d) should be similarly modified. There are several changes and clarifications required to make your instrument certification procedures both effective and useful, however, it is presumed that this type of regulation will be addressed separately and/or possibly under Appendix E, which has been reserved for quality assurance provisions.

2. D-206, D-611

Comment: In paragraphs 60.47a(e) and (f) a greater amount of time per day should be allowed for calibrations and routine maintenance for reasons stated below, "All continuous monitors are required to have their calibration checked at least once daily. Your allowance here of one hour per day seems adequate, although with our current instrument, this would limit the automatic calibration cycle to once every two hours, and current practice shows many operators are selecting an hourly calibration check interval. In this instrument each calibration value requires one minute, and there are four values to be determined: SO_2 zero, SO_2 span, NO zero, and NO span. As a result, each complete cycle requires four minutes. I believe that the allowance could be made larger, but it should be noted that the calibration time allowance need not be considered as downtime from a data availability standpoint. For short calibration intervals, there is no substantial data degradation if one was to interpolate the actual measurement value during calibration by averaging the measurements before and after the calibration cycle."

3. D-206

Comment: Under paragraph 60.47a(e) no provision is made for developmental testing of new instruments or configurations. "In the area of FGDS, you have proposed a commercial demonstration permit concept, and I believe a similar provision for new promising instrumentation would help to assure the acceptance and development of new and improved equipment. Your current proposal only penalizes any operator who would like to cooperate with a vendor in the evaluation of new improved instrumentation, and such developments are needed in this area of application (FGDS)."

4. D-206

Comment: Under 60.47a no provision is made for non-routine maintenance of continuous monitors. "Certainly your provision for mandatory manual stack sampling is not a realistic alternative to non-routine maintenance of the continuous monitors. We believe that the requirements for this activity during monitoring system downtime is a totally unworkable solution. This conclusion is based on the following:

- The training required to obtain dependable results.
- The loss of competence associated with occasional use of the skills.
- The near impossibility of paying people enough to keep them involved in this activity and to make them "climb the stack."
- The often near impossible working conditions -- at night, in the winter, during snowstorms, rainstorms, thunderstorms, or windy conditions.

We firmly believe that some realistic allowance must be made for anticipated monitoring system downtime or non-routine maintenance.

5. D-206

Comment: The commentor feels that the eight hours per month for routine maintenance allowed under paragraph 60.47a(e)(2) is inadequate for anything but a standard non-wet scrubber application for following reasons: "It should be noted that wet scrubber FGDS also present a very difficult measurement environment. With your proposed SO_2 emission limits, it is doubtful that any untreated bypass gas can be blended into the scrubber effluent and with the cost of reheat rapidly escalating, the actual gas temperature and dewpoint temperature will be equal. This means that any slurry carryover or demister discharge will remain as entrained water droplets and pose a real blockage threat to instack filters, which are typically used in extractive and short-path in-situ gas measurement systems. Even long-path or across-stack insitu systems are bothered by such entrained water if not from a gas restriction standpoint as a threat to light transmission, as the drops absorb and scatter the measurement light beam."

6. D-206

Comment: The required measurement ranges shown in subparagraph 60.47a(g)(5) vary too widely for simple, reasonable instrument performance. "The number of required measurements ranges should be restricted to something like a 3 to 1 range, for example, 500, 1000, and 1500 ppm, within a single instrument configuration to ensure instrument performance, simplicity and reasonable price. Most current instruments also include only a single span cell or reference value device which is used to verify the upscale calibration. Unless you wish to change this current practice, the requirement to change ranges frequently should be avoided, or minimized."

7. D-206

Comment: The opacity span value of 60 to 80% shown in paragraph 60.47a(g) should be changed to a simple round figure type of scaling. "We believe the range should be expanded to 50 to 80% for stack exit opacity indications which would allow at least one (50%) round figure selection. Current instruments which would be used for such applications have full scale ranges of 10, 20, 30, 50 and 100% opacity, corrected for stack exit conditions."

8. D-288

Comment: It is not clear whether downstream SO_2 monitors can be located after particulate collector to take advantage of any SO_2 absorption on collected particulates.

9. D-455

Comment: In 60.47a(g)(5), the requirements for determining the span values for the analyzers will result in nonstandard spans. Most instruments have standard ranges such as 0-500 ppm, 0-1000 ppm, etc. There is also a requirement that the span of the analyzers be changed when the fuel sulfur changes by 0.5 percent. This is totally impractical since fuel analysis results are not known until 2-3 days after the fuel is burned. It is suggested that analyzer spans be determined by the anticipated SO_2 concentrations. The analyzer range could then be rounded off to the next 500 ppm higher range to ensure that the analyzer would operate on-scale.

10. D-436, D-611

Comment:

- 98.9% requirements for data availability are not justified with respect to current technology.
- 90-95% capability is based on limited experience and factory authorized maintenance and on-site spare parts.
- EPA should revise 8-hour maximum in 60.47a(e)(2).
- more detail is required on back-up system requirements (e.g., calibration, running time, etc.) since they cannot be turned on in an emergency.

11. D-218

Comment: Lack of a continuous monitoring instrument for particulates will cause enforcement problems.

12. D-611

Comment: The proposed procedures for monitoring system performance evaluations and calibration checks for SO_2 (Section 60.47a(g)(5)) are unrealistic because,

- continuous monitors should be calibrated at span concentrations which more closely correspond to the expected operating conditions
- sources will be unable to comply with the SO_2 respanning requirements since they will have no means of determining when the SO_2 concentration in the fuel changes by 0.5 percent or more
- many state-of-the-art continuous monitors are incapable of being respanned.
- EPA has not developed a protocol or quality control quidelines for NBS traceable gases and has not

prescribed adequate methods for sampling from gas cylinders.

13. D-588

Comment: Paragraph 60.47a(d) implies that CO_2 is an acceptable diluent parameter for FGD without supporting data. The October 6, 1975, Federal Register specifically discourages CO_2 as a diluent measurement downstream of lime or limestone FGD.

14. D-588

Comment: If the following assumption is correct, it is requested that the statements listed below be clarified: "requirements for instruments on FGD's will agree with regulations set forth in the October 6, 1975, Federal Register."

- A complete SO_2 analysis every 15 minutes is deemed continuous. This should be retained in that up to six FGD points can be measured with multiplexing instruments, thus reducing capital costs.
- Certification vs. an approved instrumental technique should be permitted. Instruments that are more reliable than Method #6 are commercially available.
- An alternate means of certifying FGD instrument performance should be permitted since field performance tests are too costly and time consuming.
- Multipoint (multiplexing) instruments have been used extensively on experimental FGD's in actual field operations. Depending upon the time during which span gases are introduced during an analysis cycle, upscale and downscale response can vary by more than 15%. As long as the instrument is capable of responding within the portion of the fifteen minute cycle deemed

continuous for each sample point (in both directions) this requirement appears redundant.

- October 6, 1975, regulations are written such that they promote (actually favor in our opinion) the use of in-situ instruments because span gas introduction is not required and because of the requirements to measure SO_2, NO_x and Opacity (which can be accomplished with a single instrument). This of course is cost effective, but the FGD problem is different. Here, the instrument is being used to calculate SO_2 removal efficiency and absolute SO_2 in the final effluent. Consequently, we believe that all instruments should be subject to the same requirement (i.e., use of span gases). This is especially important since certain in-situ monitors have been improved such that zero air can be introduced. If this can be done, it leads one to believe that span gases can also be introduced. Moreover, in the case of FGD's, multipoint instruments in many cases will lead to the most cost effective approach. Alternately, calibration standards can be written that permit optical calibration for extractive or in-situ devices using gas bottle filters. Since diluent measurement is required in EPA's September 19, 1978, proposal on inlet and outlets. The need for span gas introduction at probes is not needed.

- Most instruments used to measure SO_2 in steam generating plants measure on a wet basis and correct for moisture to calculate lbs. per 10^6 Btu. An EPA representative reported success with moisture estimation at the Battelle Institute FGD Symposium held December 12, 1978. Here, a multipoint SO_2 analyzer was used and moisture was estimated from condensate trap temperature measurement. We believe this to be a viable approach and especially since we know of no instrumental method in sufficient wide use that can measure with 1.5 percent accuracy.

Monitoring Instrument Accuracy

1. D-256, D-259, D-477, D-491, F-1x

Comment: There are no data to prove continuous monitors perform accurately.

2. D-471

Comment: Experience with monitoring instrument accuracy specifications is ± 20% relative to imprecise manual methods.

3. D-588

Comment: In favors of multipoint SO_2 instruments because a multipoint SO_2 analyzer calibrated improperly and having a 20 percent variance from Method #6 due to either a high or low reading would still provide data from which FGD removal efficiency could be determined. Whereas, two single point instruments of the same or different manufacturer could still be certified with a +20 percent error and a -20 percent error. In this case, instruments would not provide data suitable for determining FGD SO_2 removal efficiency.

Monitoring Instrument Reliability

1. D-153, D-168, D-256, D-205, D-373, D-397, D-425, D-467, D-476, D-477, D-491, D-585, D-657, F-1b, F-1g, F-1w, F-1x, F-2

Comment: Continuous monitoring equipment is unreliable and serious problems exist in complying with the standard.

2. D-206

Comment: System reliability would be much higher if dedicated instruments were used at each measurement point rather than any other type of multisensor/single instrument approach.

3. D-206

Comment: Continuous monitoring system reliability is not dependent on just the reliability of a single element. "One must consider all the identificable and required elements involved in a system -- this includes the pollutant monitor, diluent monitor, computerized data logger and processor and I/O terminal. Strip chart recorders are also involved in manual data collection systems. In a four-element system with each element possessing a reliability of +90, the overall reliability is only 66%."

4. D-263

Comment: The commenter operates name brand continuous monitoring equipment which is usually operational only 5 days out of 30. Typical down time is 95%. The cost estimate for hourly manual sampling under these conditions would be $1.5

million per year. The reliability of continuous monitors must be improved and/or the manual sampling requirement relaxed or deleted entirely.

5. D-464, F-2

Comment: Redundant monitoring systems frequently do not improve system reliability since backup monitors often fail at the same time as the on-line system (e.g., after a lightning strike).

6. D-471

Comment: The following comments regarding monitors are submitted:

- Opacity monitors installed in September 1977 have yet to operate successfully. Microwave interference is suspected. The point is one of uncertainty as to capabilities of devices under varying conditions.
- Experience with monitors has been disappointing with regard to malfunctions.

7. D-626, F-1w, F-1x

Comment: The court held in Portland Cement vs. Ruckelhaus 486F 2d 375 (DC Cir. 1973) that a monitoring requirement which is part of a standard, violation of which can result in an immediate enforcement action must be demonstrably reliable. If continuous SO_2 stack monitoring is not technologically feasible now, that method can be used as an alarm system with follow up by manual testing.

Continuous Monitoring

1. D-224, D-253, D-256, D-259, D-287, D-440, D-447, D-458, D-459, D-463, D-464, D-488, D-490, D-498

Comment: Continuous monitoring with no exceptions is unjustified and unrealistic based on costs, manpower and/or state-of-the-art of instrumentation. It does not improve emissions in any significant way.

2. D-253

Comment: Section 60.47a(e) appears to make part (f) inapplicable unless (f) is made subpart (3) under (e).

3. D-300

Comment: At least 24 hours per month should be allowed for routine maintenance.

4. D-411

Comment: In favors of continuous monitoring

5. D-455, D-491, D-611

Comment: The requirement to determine compliance with SO_2 and NO_x emission limitations and with the SO_2 percentage reduction by using continuous monitors is unrealistic because,

- This is a new, unproven technique
- Continuous monitors are neither reference methods, equivalent methods nor alternate methods
- Allowed and inherent inaccuracies of continuous monitor data preclude their use for compliance determinations. These inaccuracies include:

(a) allowed inaccuracies of pollutant monitors, relative to reference methods

(b) inaccuracies of diluent monitors

(c) allowed errors due to installation of monitors at other than ideal locations

(d) degradation of monitors with time

- Allowable inaccuracies may reach ± 35 percent.
- Monitor accuracy is extremely critical when determining compliance since many sources will operate near compliance levels.

6. D-463

Comment: The most sensible approach for Western utilities to determine whether they are in compliance with the percentage reduction requirement for SO_2 emissions is the "as fired" basis found in proposed section 60.47a(b)(3). This option should be retained because EPA's analyses of the benefits of the "as fired" sampling technique is correct.

7. D-631

Comment: In favor of the real time transmission of monitoring and scrubber data to EPA to monitor performance levels.

8. D-611

Comment: The accuracy and precision of the two methods for conducting performance tests differ. The difference between the results obtained by initial performance tests and continuous monitors can be significant. The proposal does not specify which method takes precedence.

9. D-611

Comment: The proposal requires that continuous monitoring comply with the performance specifications of Appendix B of 40CFR60 yet,

- nearly one-half of all continuous gas monitors which have been subjected to Performance Specifications Tests have failed
- a typical generating unit, employing parallel scrubber trains and ten gas monitors, may have less than a 1 percent chance of all monitors passing the initial performance tests

10. F-1c

Comment: If continuous monitoring is of questionable feasibility at present, it should be deleted from the present standard and promulgated later as part of a separate regulatory process.

Backup Manual Monitoring

1. D-168, D-205, D-212, D-215, D-216, D-224, D-227, D-232, D-253, D-256, D-259, D-263, D-272, D-300, D-322, D-397, D-401, D-404, D-407, D-413, D-417, D-423, D-425, D-437, D-440, D-444, D-449, D-455, D-458, D-464, D-467, D-471, D-476, D-486, D-488, D-491, D-611, F-1x

Comment: The proposed regulations for monitoring when continuous monitors are not operable are unreasonable. One or more of the following reasons were cited by each commenter.

- It requires several hours to set up for the first sample even if a standby crew is on duty. It may go beyond a full day if the facility does not have an in-house test crew. A lag time is needed before first test is required.
- Simultaneous failure of more than one monitor compounds the problem.
- Failure of a monitor does not in itself indicate failure of control equipment.
- Hourly tests are unreasonable and impractical. Manual tests should be deleted entirely or required only one or two times per day.
- Sampling from a stack is almost impossible in severe weather. There should be some exceptions.
- This requirement is extremely unjust for small utilities.
- Test results are not available in time to provide useful feedback.

2. D-366

Comment: A requirement for minimum downtime is more appropriate than hourly manual testing.

3. D-366

Comment: Particulate testing when an opacity monitor is down is unnecessary.

4. D-366

Comment: Since there are no control devices for NO_x emissions, what will manual testing accomplish?

5. D-366

Comment: SO_2 testing at the inlet is unnecessary during downtime.

6. D-206, D-215, D-227

Comment: The log of critical operating parameters should be used instead of manual backup for continuous monitors. The reasoning is as follows: "For example, a typical wet scrubber FGDS can be reliably evaluated from a knowledge of pressure drop, pH, slurry feed rate, make-up water feed rate, damper positions, etc. Therefore, we would recommend that such critical parameters be continuously monitored and used for proof of compliance during periods of instrument downtime as an alternate to manual sampling. Even if the absolute readings at any given point in time are not totally conclusive, the relative indications occurring with known emission levels priorto instrument failure can be correlated with operating conditions during the time the instrument is down to ensurethe continuous and reasonable operation of the controlequipment during this time.

Certainly, with moderncomputerized data logging and report generation systems,it isa fairly simple and inexpensive matter to monitor andrecord such additional process information."

7. D-627

Comment: In view of the unreliability of monitors and the expense of continuous manual backup, none of the alternatives for meeting the continuous monitoring requirements is viable. Up to 3 hours outage of continuous monitors should be allowed for on-site repairs followed by manual testing on a 3 hour schedule.

2.5.3 - 60.48a Compliance Determination Procedures and Methods

1. D-223

Comment: Change the title of 60.48a to "Performance determination procedures and methods" to differentiate between performance testing and ongoing compliance tests.

2. D-404, D-413, D-417, D-455, D-458, D-486

Comment: The regulation should specify that particulate matter is measured immediately after the particulate control device. This is related to comment 6 on the particulate matter emission limit (D-153).

3. D-438, D-448

Comment: Compliance should be determined by performance tests under existing EPA reference methods.

4. D-455, D-491, D-611

Comment: There is a way to ensure compliance with standards without the reliance on inaccurate, unreliuable monitors. The monitor performance specifications were written to apply to "indicators of control device performance." Monitors can be retained for the purpose of indicators. SO_2 and NO_x analyzer data could then be handled like opacity data. Indicated excess emissions or low removal efficiency could be reported quarterly. Based on these data, the agency could request a formal compliance test if necessary. The effect would be to require compliance of the FGD system on a short-term basis where indication of continuing compliance could be demonstrated on a long-term basis with monitors as is now being done for particulate control devices.

5. D-455, D-611

Comment: A much simpler way to indicate compliance is to determine a monthly average fuel input sulfur, apply the fuel cleaning credit, and monitor SO_2 emissions out of the scrubber. This procedure would eliminate unnecessary monitors and fuel sampling and would therefore be subject to fewer cumulative errors.

6. D-467

Comment: Exemptions during startup, shutdown, etc., fail to provide for certain operational startup activities such as balancing of the turbine generator.

7. F-1b

Comment: Because of the unreliability of monitoring equipment and the undue cost of continuous monitoring, the provision should be eliminated. Continuing compliance should be enforced by performance testing on a spot-check basis. If the continuous monitoring provision is to be retained, then a standard should be placed on manufacturers of monitoring equipment to guarantee the required high reliability.

8. D-611

Comment: The proposed standard requires that daily emission values are determined as the arithmetic average of the emission measurements derived either from continuous monitors or manual methods. EPA has not presented an adequate analysis of the biases associated with arithmetic averaging of emission values as opposed to proportionally weighting the emission values with respect to production rate parameters. This may be important if scrubber performance varies with electrical load factors.

2.5.4 - 60.49a Reporting Requirements

1. D-223, D-250

Comment: Report requirements should be limited to either the monthly average or a simple report of periods of excess emissions.

2. D-223, D-263

Comment: The cost of data reduction and reporting is not given. Was it considered? For example a typical small computer would cost from $35 to $75,000.

3. D-322

Comment: Utilities are responsible for compliance. However, they should not be responsible for identifying excess emissions. Unless there is a logical use for the reports, they should not be required.

4. D-256

Comment: Section 60.49a(f) should allow at least 45 days for submission of a report. Extra personnel on shifts are unjustified.

5. D-206

Comment: There are several related areas where the contents of section 60.49a need clarification or revision.

6. D-588

Comment: No maintenance or downtime should be charged to an instrument when the FGD module is down since it is an opportune time to perform maintenance and calibration.

7. D-611

Comment: In the preamble to the proposed Subpart Da, EPA currently states that opacity readings taken before and after a FGD system will not necessarily provide the same results and that opacity monitoring should not be used as a compliance determinant with the out-of-stack opacity standard. These statements are not explicitly reflected, nor directly implied, in the proposed Subpart Da itself. The ambiguities in the reporting requirements of section 60.49a(e) imply that reported transmissometer data might be used for opacity compliance determinations, since excess emission reports derived from opacity monitors output must be in terms of the standard.

8. D-627

Comment: The requirement for emission monitoring data is unreasonable in terms of workload on plant personnel and it will far exceed EPA's ability to store, retrieve and review. EPA should require reporting of the data on a "by exception" or occasional basis only--e.g., when required for EPA's specific use, on a fixed schedule, or by a random sampling approach.

2.6 Appendix A, Reference Methods

1. D-179

Comment: Requirements to use EPA Method 19 with no provision for new techniques is unreasonable.

2. D-224

Comment: The method for analyzing daily "as burned" fuel is too complicated.

3. D-247

Comment: For Methods 5 and 17, the standard should stipulate "dry filter catch only" due to the fact that much of the emissions is in the vapor state while going through the particulate control device.

4. D-280

Comment: Stack testing for SO_2 should be eliminated if pretreatment is the only control used.

5. D-404

Comment: The test methods for particulate matter do not appear to be applicable to testing in the ductwork between particulate control and scrubber.

6. D-437

Comment: Question the hourly sampling of coal (200 lb/hr by ASTM standard).

7. D-440

Comment: Question the 24-hour lot size in paragraph 3.3, Appendix A when paragraph 2.1.2 allows a 90-day lot size. Question the burden of analyses on a 24-hour basis.

8. D-455

Comment: There are no procedures to account for the fact that a plant might receive some precleaned fuel and some that is not precleaned. In the Method 19 calculation procedure, each lot of coal has the same mathematical weight regardless of the lot size. Under the proposed procedure, one could receive a one-car lot of precleaned coal and apply that credit to all coal burned for a 3-month period. Fuel precleaning credits should be determined on a Btu-weighted basis.

9. D-455

Comment: Method 19 does not qualify as a reference method since it is only a calculation procedure. It does not stand alone since it continually refers to subparts. If it is to be a reference method then it should stand alone, and an analysis of the total error should be performed on the Method. I would think that one would be surprised if this is done since I have estimated the error to be in excess of 50% because of monitor and fuel analysis errors.

10. D-455

Comment: No mention is made of the fact that certain scrubbers absorb CO_2 and that this can cause significant F-factor errors. This should be addressed.

11. D-455

Comment: It is stated in Method 19 that since reheaters only require from 1 to 2 percent of the total heat input of the boiler, their effect can be ignored. Unfortunately, direct-fired heaters are notoriously poor combustors and introduce significant stratification, usually close to the sampling point. Sampling should not be done downstream of a direct-fired reheater unless the gas is well mixed.

12. D-471, D-491

Comment: Question the accuracy of Methods 5, 6, 7, and 17 at the low emission levels of the standard.

13. D-206

Comment: EPA's attention was focused too much on the theoretical accuracy of the various test methods rather than practical accuracy.

14. D-588

Comment: In general, all requirements are stated in terms of 24-hour averages. Can it be assured that the ± 1.5 percent allowable error discussed in 5.3.1.2 on page 43 FR 42182 refers to Bws derived data averaged over a 24-hour period?

15. D-588

Comment: The applicability of equations in Section 5.3.2 should be restricted to data obtained upstream of a flue gas desulfurization system.

16. D-611

Comment: Under Method 19, methods for determining heat input rates for the various fuels are not specified.

17. D-611

Comment: Method 19 does not specify the frequency of calculating F-factors. The conditions under which the F-factor must be recalculated should be identified so that the accuracy of the emission or percentage reduction calculation can be determined.

2.7 Economic Impacts

Cost to Consumer

1. D-117, D-152, D-157, D-169, D-198, D-290, D-462, F-1c, F-1i, D-631, F-1t

Comment: In favor of full scrubbing, a low ceiling or cap (maximum emission level), and/or a percentage reduction in SO_2 emissions equal to or greater than the 85 percent proposed on one or more of the following grounds.

- cheap power is impossible, prefer to pay now
- strict standards will promote use of local coal
- utilities should pay the full cost of burning coal
- 2 percent of capital costs or 48 cents/month in household bills for control is not unreasonable
- will create more jobs and improve the economy
- alternative power sources will become more competitive
- survey in one locality showed consumers are willing to pay for clean air
- San Juan (New Mexico) Generating Station scrubber achieves 90 percent, requires only 4 percent of total input energy, and produces a marketable product
- partial scrubbing gives artifically preferential treatment to low-sulfur coal

2. D-22, D-28, D-31, D-34, D-40, D-62, D-64, D-88, D-90, D-100, D-114, D-132, D-145, D-150, D-153, D-167, D-168, D-216, D-223, D-224, D-225, D-232, D-234, D-237, D-238, D-242, D-244, D-251, D-252, D-259, D-261, D-263, D-265, D-267, D-270, D-271, D-274, D-276, D-279, D-284,

D-286, D-287, D-289, D-294, D-297, D-298, D-299, D-300, D-303, D-317, D-319, D-322, D-329, D-332, D-334, D-340, D-344, D-346, D-347, D-348, D-349, D-368, D-370, D-403, D-404, D-405, D-407, D-418, D-421, D-422, D-431, D-457, D-458, D-466, D-467, D-474, D-491, D-498, F-ls, F-lz, F-ly, F-lx, F-laa, D-514, D-523, D-598, D-599, D-600, D-625, D-628, D-634, D-635, D-639, D-642, D-643, D-667, D-670, D-674, D-682, D-683

Comment: Oppose the regulation as proposed; prefer no change in current standards or partial scrubbing with sliding scale and/or higher floor as proposed in DOE and UARG alternatives. Proposed regulation opposed for one or more of following reasons:

- too expensive
- retail power cost increase of 4 to 13 percent in a particular utility
- estimate increase from present $6.08 to $12.05/customer/month for controls at a particular plant
- not cost effective in terms of cost per ton of SO_2 captured
- inflationary
- cost to consumer could reach 20 percent of bill in particular situations
- counter-productive (full control may produce more SO_2 emissions than partial control)
- discourages use of coal and increases use of oil
- decreased economic growth opportunities in Western coal producing states
- economic studies neglect secondary effects on state regulations, ripple effect through economy

- question whether model capability can assess economic impacts within a region
- sludge costs of \$19/Mg underestimated by factor of 2 to 4
- opposes stating effect in terms of monthly cost to consumer as this neglects pass through costs from industry
- inequitable regional impacts

3. D-303

Comment: SO_2 standard hurts New Mexico coal industry.

4. D-270

Comment: Regulations provide incentive to continue with oil and gas plants.

5. D-254

Comment: Concerned about the multiple effects of all rules on economic growth and resource development.

6. D-262, D-418

Comment: The economic model understates the relative costs of full scrubbing.

- Marginal costs increase disproportional to benefits with increased standard
- Understatement of Wyoming Powder River Coal Reserves (estimated 15 billion tons recoverable)
- No sulfur credit in model for washing coal
- Oil prices projection is too high
- Inflation rate is too low
- Time horizon in the analysis is too short

- Assumptions are not adequate, specifically,
  - Does not obtain total system capacity requirements based upon reliability criteria
  - Does not simulate utility operations, i.e., does not carry out hour-by-hour dispatch and assumes the same number of spare scrubbers for full and partial scrubbing whereas the number should be based on reliability analysis
  - Is more sensitive to the price of oil (alleged not to be a major consideration in utility operations) than to floors (maximum sulfur content at which scrubbing not required)
  - Should have used a range of values for electric growth and discount rates since there is no consensus on what these will be
  - No analysis of 30-day averaging of emissions

7. D-473

Comment: For the Edgewater V facility in Wisconsin, costs of the proposed controls were calculated to be $319.4 million in 1983 dollars with a maximum ambient air quality improvement of 5 percent over what would be achieved with the use of low sulfur coal.

8. D-479

Comment: Both transportation and labor costs are stated as projected to increase at a rate 1 percent above the assumed rate of 5.5 percent. Federal strip mine regulations, effective January 1979, are cited as increasing coal production costs.

9. F-1c

Comment: The economic model is deemed to overstate the relative costs of full scrubbing for the following reasons:

- Substitution of oil for coal because it is cheaper will not be allowed and should not be provided in the model
- Reduction of SO_2 emissions under other requirements (such as PSD and SIP) should not have costs charged to revised NSPS

10. F-1y

Comment: The national average of economic impacts on consumers is misrepresentative. The heaviest burden will be felt by fast-growing utilities and in regions such as the West which are experiencing and will experience higher growth rates.

11. D-611

Comment: Calculations by the National Economic Research Associates, Inc. show the annual costs of proposed revisions higher by from 2.1 to 2.5 times those calculated by the model EPA reported in the Federal Register. Also the incremental costs of full scrubbing over those of a sliding scale are projected to be higher. The differences appear to result from assumptions regarding a higher growth rate in demand for electricity, scrubber reliability, and particulate control costs. When these are adjusted to reflect more nearly the assumptions in the ICF, Inc. model reported by EPA the results are closer but costs of full scrubbing are still higher as calculated by NERA.

These differences also affect estimates of the cost per ton of SO_2 removed. Depending on whether or not greater scrubber reliability and lower electricity growth rates are assumed the costs may be less than those reported by EPA or even higher.

Electricity demand growth rate averaging 4.4 percent per year used by ICF Inc. in August runs reflects an overreaction to increased costs and is too low. Prefer 5.3 percent annually through 1990, as used by NERA.

Models typically calculate minimum costs; hence, the ICF Inc. model probably underestimated actual costs.

12. D-491

Comment: The proposed regulation for full scrubbing is not cost effective when compared with the alternatives for a sliding scale proposed by UARG and DOE. Full scrubbing would achieve a 16 percent reduction in SO_2 emissions at a 54 percent increase in costs. In terms of additional SO_2 removed, the incremental cost per ton under full scrubbing is \$2500 over the DOE proposal and \$1333 over the UARG proposal. A recent (1975) study by the National Academy of Science estimated the benefits of SO_2 removal to be \$200 per ton. This study included health benefits not at issue here. The cost per ton of SO_2 removed under full scrubbing is 4 times that under partial scrubbing.

13. D-625

Comment: Scrubber technology has been determined by EPA as mature. Therefore the assumption of declining capital costs for controls used in the model are unrealistic and understate both the incremental and total costs of full scrubbing relative to partial sampling.

The scrubber reliability figures and the operating and maintenance costs used in the model do not reflect the performance levels actually achieved. Consequently both the costs and the SO_2 emissions (resulting from inability to achieve 100 percent compliance) under full scrubbing will be greater than those projected by the model.

14. D-514

Comment: It is unlikely that midwestern coal will keep pace with demand so western coal will eventually be used anyway.

15. H-13

Comment: The shifts in the price level resulting from the one regulatory action of revised NSPS (increase of 0.6 percent to 1.1 percent by 1990 and by from 1.2 to 2.1 percent by 1995) are seen as having considerable effect on the national economy and no significant differences in benefits appear among the analyzed options.

16. F-1r

Comment: In some Appalachian states, the model projects that coal production will actually decrease from the 1975 level under

EPA, DOE and UARG proposals. This is not fully credible and casts doubt on the model.

Cost to Other Industries

1. D-5, D-163, D-191, D-233, D-422, D-452, D-454, D-478

Comment: The proposed standard with full scrubbing is inflationary, having higher marginal costs than the alternative proposals that call for partial scrubbing. These costs will adversely affect industry, especially metals and mining.

- Percent increase of marginal costs of electric generation above current NSPS is 15.08 under full scrubbing, compared with 10.56 and 7.48 under the partial scrubbing alternatives proposed by DOE and UARG respectively.

- 40 percent of electricity is used for manufacturing

- Detrimental effect of full scrubbing on iron ore pellet producing industry

- Steel industry would see a 9.5 percent increase in electricity rates reflected as a cost increase of $1/ton of steel shipped.

- Increased costs in cents per pound of non-ferrous metals under full and partial scrubbing alternatives:

	Full	Partial	
		DOE	UARG
Aluminum	2.2	1.2	1.0
Copper	0.4	0.19	0.16
Lead	0.06	0.05	0.036
Zinc	0.49	0.28	0.19

- In 1990, total increases in production costs of non-ferrous metals under full scrubbing will be more than double the increase under partial scrubbing, the amounts ranging from about $1 million for lead to over $11 million for copper.

2. D-321, D-369

Comment: The impact on the ESP industry in an estimated shift of $500 million to the baghouse industry is regarded as unfair.

3. D-215

Comment: The increases in cost to local and state governments for administration and enforcement are unwarranted.

4. D-276

Comment: Oppose the standard since it impacts the transportation infrastructure and may impact the use of coal by Midwest industries.

5. D-210

Comment: Oppose the standard due to excessive costs to smaller power plants.

6. D-486

Comment: Reliability of pollution control equipment required by regulation as proposed would be particularly expensive for utilities with high load factors that provide little opportunity for shifting. These costs would directly affect major industries in the vicinity of this Upper Midwest plant, especially iron mining and taconite processing.

7. D-491

Comment: Full scrubbing will adversely affect the U.S. balance of payments in foreign trade. Oil and gas imports required in

1990 under it are projected by NERA to total $8.2 billion compared to $4.4 and $6.0 billion under the UARG and DOE proposals, respectively.

8. D-421, D-508, D-643, F-1u

Comment: Marginal cost increases of the revised regulation are unduly high under full scrubbing. These are the cost increases in new facilities alone and represent 7.48 percent under the UARG proposal, 10.56 under the DOE proposal, and 15.08 percent under full scrubbing. Commonly, large industrial users of electricity are sold incremental electricity only at marginal cost. Therefore, the inflationary effect of the proposed revisions on energy-intensive industries will be far greater than indicated by consideration of average cost increases. The results will operate inequitably on a regional basis. Full scrubbing has a much greater potential than the sliding scale for disrupting regional employment. Western paper industries would be at an economic disadvantage under the proposed SO_2 standard. Specifically, under full scrubbing the increase for the upper midwest would be 13.32 percent as against 10.52 percent for the rest of the nation, whereas under the DOE proposal the difference is only 5.99 vs 5.98 percent.

9. D-491

Comment: The cost to industry will be felt in decreased coal production and employment in the Appalachian coal fields, which the Clean Air Act Amendments were designed to assist. Compared to the UARG sliding scale proposal, as projected by National Economic Research Associates, Inc. full scrubbing will result in Appalachian coal production in 1990 that is 12 million tons less and in employment of 6,000 fewer miners.

10. D-628

Comment: Section 311 of the CAA Amendments calls for a study of the effects of NSPS on the job market. Shifts in job availability under the alternatives considered should be examined regionally and subregionally for the mining industry and for other industries that shift production due to electricity costs. These data should be part of the record before a final decision is made in revising NSPS and the data should particularly include the new options reported for the first time in the Federal Register in December.

11. D-516

Comment: Economic Impact for Midwest Continent Power Pool:

- 13 percent increase under full scrubbing in rate of paper and allied products industry versus 6 percent increase if DOE plan adopted.
- Paper industry major growth industry for northern Minnesota and Wisconsin

- Economic impact will be especially felt by rural coops and small municipalities where major growth is occurring, e.g. $39-137/year in 1977 dollars of additional increases.

12. D-290

Comment: Regional industries will be aided by requiring the same control requirements on all coal, regardless of sulfur content.

Measures of Economic Impact

1. D-611

Comment: Planned utility capital investment is a misleading measure of the economic impacts of proposed revisions to NSPS. Because replacement of obsolescent plants will be more costly under the revision than under continuation of the present standards, fewer replacements will be made. Therefore, less capital expenditure will be reflected and the economic impacts are misleading.

The cost of the proposed revisions will grow over time because the affected generating capacity will increase. EPA's use of 1990 present value costs (43 FR 42164) fails to take into account increases beyond that date and understates the impacts of the proposed revisions.

Great Lakes Transportation

1. D-67, D-214, D-245, D-265, D-267, D-357, D-598, F-1d

Comment: Concerned that proposed SO_2 standard would curtail shipment of western coal via the Great Lakes.

- 7th District of Wisconsin would suffer serious economic decline
- Cost of transporting and handling western coal is borne directly by consumer through fuel adjustment clauses while pass through of scrubber costs are subject to rate increase hearings
- Buffalo Terminal to handle 14 million tons of coal/year. Cost $50 - $150 million, $1 million already spent on design
- Use of local or regional coal is critical to economic well-being of many areas
- Great Lakes transportation is very economical
- Use of western coal would increase construction of Great Lakes port facilities

2.8 Environmental Impacts

General Comments on Environmental Impacts

1. D-28

Comment: More study is needed of the environmental impact of coal cleaning.

2. D-245

Comment: Concerned over impact of creating coal boomtowns.

3. D-335

Comment: See no need to scrub in the middle of Iowa where record crops are reported.

4. D-152, D-432, D-434, D-462, D-631, D-657

Comment: There is a need to minimize the various harmful effects of pollution:

- on crops, livestock, property and human health
- significant deterioration of pine trees and lichen on Montana ranch adjacent to Colstrip
- long range impacts of sulfur rain, sulfate transport, etc.

5. D-599

Comment: Full scrubbing will have net adverse environmental effects:

- discourages investments in front-end cleaning technology
- increases scrubber sludge waste
- increases water consumption
- removes economic advantage of low sulfur coals which emit less pollutants.

6. D-611

Comment: The incremental reduction in SO_2 emissions over that achieved under continuation of the current NSPS is somewhat greater as calculated by National Economic Research Associates, Inc. for the proposals advanced by EPA, UARG and DOE than the model estimates reported by EPA in the Federal Register for September 1978. The differences result from estimates that lower sulfur coals will be burned because the cheaper control costs associated with them will more than offset their higher purchase price.

Regional impacts in SO_2 emissions as calculated by National Economic Research Associates, Inc. show that under the proposed revisions to NSPS those areas with the highest emissions (Middle Atlantic and East North Central) are not the ones where the greatest reductions will be achieved. Emissions in the Middle Atlantic region are calculated to increase under full scrubbing while declining under the sliding scale projected by DOE and UARG.

7. D-627

Comment: The proposed NSPS with full scrubbing will not result in a reduction of SO_2 emissions or of ambient concentrations for new power plants. Instead, when low sulfur coal is used, the new plants will simply be much larger, up to the maximum size determined by the combination of the revised

NSPS and limitations imposed by PSD Class II Standards for new sources.

8. D-625

Comment: The SO_2 emissions will be greater than those projected by EPA under full scrubbing. Technology will not be able to achieve the 100 percent compliance assumed by the predictive model.

9. D-631

Comment: The Clean Air Act requires EPA to favor health and environmental protection in resolving uncertainties in the evidence of adverse effects. Adverse environmental effects must be minimized even if technology is forced and control costs are not "grossly disproportionate."

10. D-491, F-1y

Comment: Full scrubbing would require much more lime scrubbing, as distinguished from limestone scrubbing, than the UARG proposal. The increase in lime production would result in increased air and water pollution and solid waste storage problems at the lime production facilities.

11. D-592

Comment: Articles and studies are submitted in support of full scrubbing addressing:

- the role of SO_2 in obscuring visibility
- formation of harmful sulfates when SO_2 and particulate matter interact

- harmful effects reported from NO_2

12. D-598

Comment: The effect of a sliding scale is seen as reducing the net emissions of pollutants in the Great Lake states.

Sludge

1. D-175, D-210, D-223, D-224, D-227, D-231, D-234, D-250, D-252, D-254, D-274, D-300, D-314, D-322, D-332, D-347, D-361, D-367, D-373, D-446, D-458, D-459, D-467, D-469, D-473, D-491, D-523, D-657, D-735

Comment: Adverse effects of sludge disposal were not adequately assessed and/or the costs were underestimated.

- Handling of solid waste from small units particularly burdensome
- Cost of sludge disposal
- Sludge disposal leaching
- Full scrubbing produces 50 percent more sludge than DOE proposal
- Excessive land areas will be required for sludge disposal
- Availability of sludge disposal sites may be severely limited under other legislation such as the Surface Mining Control and Reclamation Act of 1977 and the Farmland Preservation Act of Wisconsin. Impact of farmland loss in Wisconsin may be greater than that of allowing an incremental increase in SO_2 emissions.

2. D-419

Comment: Scrubbing anthracite coal would produce only 30 lbs of sludge per MW hour compared to 130 lbs/MW hour for 3.5 percent S bituminous coal.

3. F-1t

Comment: The land required for sludge and ash disposal under the proposal will amount to only about 1 percent of utility requirements for land use compared with over 90 percent for transmission lines, coal mining and transportation.

4. D-631

Comment: The adverse environmental effects of sludge have been grossly exaggerated. The benefits of scrubbing far outweigh the detriments of sludge disposal.

5. D-491

Comment: Full scrubbing will severely impact the problem of solid waste disposal. An estimate by National Economic Research Associates, Inc. projects the increase in scrubber sludge under full scrubbing to be 12.86 million tons - more than 6 times the increase under partial scrubbing. The sliding scale is estimated by the same projection to decrease the amount of ash requiring disposal, whereas full scrubbing will increase it. Based on disposal costs of $20 per ton, partial scrubbing will reduce expenses for waste disposal from $155 to $95 million whereas full scrubbing will increase it by $49 million.

Acid Rain

1. D-98, D-107, D-169, D-230, D-260, D-359, D-367, D-493, D-501, D-507, D-631, D-592, D-666, D-668

Comment: Concerned about acid rain if SO_2 standard is not strict.

Ambient Air Quality

1. D-166, D-230, D-267, D-271, D-294, D-331, D-370

Comment: Concerned about degradation of ambient air quality.

2. D-5, D-132, D-347.

Comment: Cite British position that some SO_2 is beneficial to agriculture.

3. D-458.

Comment: Maryland is considering relaxing the SIP for plants from 0.03 lb/10^6 Btu to current NSPS level due to the minimal air quality impact.

Prevention of Significant Deterioration (PSD) Program

1. D-130

Comment: Partial scrubbing would undermine the PSD clause in the Clean Air Act.

2. D-330, D-368, D-371, D-373, D-417, D-467

Comment: PSD should not be considered in developing the NSPS since the PSD increments are a matter for state and local agencies.

3. D-120, D-223, D-280, D-320, D-367, D-391, D-403, D-404, D-416, D-421

Comment: PSD should be considered in action.

4. D-262, D-414

Comment: PSD provides a mechanism for improving air quality and should be considered on a case-by-case basis as an alternative to full scrubbing.

5. D-320, D-410, D-433, F-ly

Comment: PSD is already too strict. It would be discriminatory to require more scrubbing than the PSD would require.

6. D-472, D-490, D-498, D-516

Comment: PSD provisions should provide sufficient environmental protection. The proposed standard would inhibit technological innovation and preempts the states from exercising authority granted in Clean Air Act to achieve optimum balance of competing factors in the design of state strategies.

7. D-482

Comment: During the three-day exemption from full scrubbing (75 percent), will the unit also be exempt from PSD?

8. D-435

Comment: PSD increments would be used up more quickly under proposed standard.

9. D-518

Comment: Worried about "grandfathering" plants. PSD regulations will come under pressure as growth takes place.

10. D-631

Comment: The NSPS must assist the PSD program by insuring that tight standards minimize threats to visibility.

11. D-501

Comment: In one county, Detroit Edison is taking 80 percent of the PSD increment.

12. F-1s

Comment: It is not necessary for NSPS to require maximum possible controls in order to prevent significant deterioration so as to meet the requirements for non-attainment areas: this is a separate consideration.

Water

1. D-263, D-265, D-271, D-320, D-321, D-410, F-1s

Comment: Concerned about water use

- Question wet vs. dry scrubbing in areas of scarce water supply
- Estimate 15 percent increase in scarce water usage.

2. D-491

Comment: Analysis of the feasibility and cost of treating potential waste streams by EPA and its contractors is totally inadequate. Specific examples from the EPA/Radian report are cited.

3. F-1y

Comment: In arid regions of the west, requirements for water by utilities already burning low sulfur coal will waste water in reducing emissions below the level needed to assure health and welfare of the population.

Other Legislation

1. D-270, F-1u

Comment: The proposed standard restricts SIP planning by setting permissible levels at the edge of available technology so that state initiative in providing the degree of stringency required by local conditions is preempted.

2. D-474

Comment: Surface Mining Reclamation Act was intended to make surface mining environmentally acceptable. Interacts with analyses since costs will be higher in the west. Also, the objective of reducing reliance on western coal is in conflict with objective of Mining Act which was to minimize the adverse effects of surface mining to permit greater utilization of the resource.

3. D-266, D-314, D-469, D-473, D-491

Comment: The effects of RCRA on sludge disposal cost were not taken into consideration.

4. D-290

Comment: Strict standards would be an aid to preventing deterioration of air standards (under other sections of the Clean Air Act amendments) and thereby would enable us to attract industry and promote county growth. A strict NSPS will save costs to local and state governments by reducing litigation when permits are sought under other provisions of the Clean Air Act.

5. D-491

Comment: Concerned about cost of sludge disposal in light of the Clean Water Act.

6. D-627

Comment: The NO_x standard can, with difficulty, be met for new boilers but is unlikely to be achieved in retrofit of existing boilers. Therefore, care should be taken to avoid any tendency to force the SIPs to reduce their requirements to similar levels.

7. D-519

Comment: The analyses fail to address the impacts of RCRA, TSCA, FWPCA.

2.9 Energy Impacts

1. D-39, D-167, D-242, F-1u, D-599

Comment: General comments on increased energy required to meet the standard.

2. D-287

Comment: The proposed standard undermines any chance to develop Intermountain Area electric power (which appears to depend on use of local Western coal).

3. D-132, D-347

Comment: Baghouses for control of particulate emissions would require significant additional energy to operate due to increased draft losses.

4. D-156, D-167, D-223, D-224, D-227, D-246, D-262, D-300, D-15, F-1y

Comment: Flue gas desulfurization energy requirements:

- increase NO_x, SO_2, and CO
- exact a 5 percent energy penalty
- encourage use of oil under full scrubbing

5. D-245, D-246

Comment: The proposed regulations will expand the available energy by allowing the use of high sulfur coal.

6. D-42, D-410, D-683

Comment: The energy penalty and costs of FGD are too high relative to the potential air quality improvement. The optimum level (in terms of health and welfare) has not been established. The standard should be withdrawn until such time as it is.

7. D-422

Comment: The standard encourages use of gas and oil instead of developing coal reserves.

8. D-491

Comment: While under all alternatives considered, the total coal production in 1990 will be less than under continuation of present NSPS as estimated by National Economic Research Associates, Inc., the relative decline will be about 5 times greater under full scrubbing than under the sliding scale proposed by UARG (144.8 million tons compared to 27.8 million). The effects will be felt in the Appalachian coal fields which the Clean Air Act amendments were intended to assist. As estimated by NERA, the 1990 difference in production of Appalachian coal between full scrubbing and the continuation of current NSPS may be nearly 3 times the difference reflected under sliding scale - 19.1 million tons vis-a-vis 6.7 million.

9. D-611

Comment: The estimates of incremental oil and gas consumption over that projected under continuation of current standards are far higher as calculated by National Economic Research

Associates, Inc. than in the estimates reported by EPA in the Federal Register for September 1978. NERA estimates of the incremental consumption are more than double those reported as projected under full scrubbing. Incremental increases under partial scrubbing are also higher than reported by EPA, but by lesser amounts.

10. D-491

Comment: The EPA SO_2 proposal has a greater adverse energy impact than the UARG or DOE alternatives because

- it would discourage the phase out of existing oil and gas facilities
- it will cause a significantly greater increase in oil demand than will the sliding scale alternative
- it would discourage strengthening of west to east transportation facilities, thus lessening the availability of low sulfur coal for non-utility use.

11. D-642

Comment: Full scrubbing as proposed would preclude the use of high sulfur Appalachian and midwestern coals that could be burned under the UARG proposal. The latter allows a ceiling of 1.5 $lb/10^6$ Btu of SO_2 with appropriate percentage reduction.

12. F-1u

Comment: Full scrubbing does not permit utilities burning low sulfur coal to use reheat for bypass and consequently increases the energy penalty over that associated with DOE and UARG proposals.

2.10 Health Effects

1. D-230, D-359, D-360, D-363, D-439, D-494

Comment: Partial scrubbing will cause increase in sulfates or trace elements. Therefore, SO_2 standards should be strict. Lane and Saskin (Air Pollution and Human Health) are quoted that reducing particulates and SO_2 would lower mortality 4.7 percent.

2. D-38, D-113, D-114, D-167, F-1z

Comment: The standards are misdirected or not needed.

- Three articles are submitted indicating SO_2 is not harmful.
- The position taken is that EPA is bombarding the public with totally erroneous claims of human health damage that are scientifically unsupportable. National resources are being wasted.
- Standards focus on short-term pollution exposure while scientific evidence shows that as much as 95 percent of all damage is from long-term exposure.
- Health effects are not an issue in Iowa. Rural America should not suffer for metropolitan problems.

3. D-631

Comment: The Clean Air Act requires EPA to favor health and environmental protection in resolving uncertainties in the evidence of adverse effects. Adverse health effects are well documented in reports such as:

- the Rall Report
- the NRDC Report on Health Effects of Fine Particulates
- Lane and Saskin - Health Effects of Sulfates and Particulates - The Estimated Economic Value of These Effects

- 1975 NAS Study - Money Value of Sulfur Emission Damages

Thus, the standard must be made very strict even if technology is forced and costs are not "grossly disproportionate."

4. D-592

Comment: Article submitted in support of full scrubbing discusses evidence for an association of adverse effects on human health and air pollution including sulfates (from SO_x and particulates) and NO_x. Some studies established significant correlation between specific adverse health effects and ambient concentration whereas others have not. It has been difficult to estimate the continuing effects of other factors to establish threshold levels; and to determine the impacts for different groups of the population. Tables are offered relating specific expected adverse health effects to quantitatively expressed pollutant concentrations in the atmosphere.

5. F-1u

Comment: Adverse health effects can result from the high cost of electricity such as the inability to provide adequate air-conditioning in nursing homes during heatwaves where deaths have been attributed to the lack of proper air conditioning.

2.11 General Comments on Entire Standard

1. D-4, D-29, D-45, D-53, D-55, D-58, D-59, D-68, D-92, D-96, D-109, D-111, D-127, D-138, D-159, D-160, D-164, D-165, D-171, D-193, D-222, D-228, D-241, D-248, D-258, D-269, D-291, D-292, D-295, D-296, D-216, D-318, D-353, D-358, D-376, D-383, D-740

Comment: Support the proposed standard with no specific reasons given.

2. D-430

Comment: The use of additives as supplemental abatement techniques was not addressed; these are opposed and should not be part of BACT but concern is expressed that they may be forced on plant operators to meet the standards promulgated:

- use of sulfur compounds to improve ESP performance is counter productive
- use of sodium compounds for the same purpose is suspect because of potentially adverse effects on both equipment and character of emissions
- use of ammonia to improve rate of NOx emissions is far from state-of-the art and may lead to significant ammonia releases.

3. D-447

Comment: EPA, in the support documents, did not treat the impacts of cycling type plants on the data used to support its proposal. Most new plants brought on line by the utility community will be cycling type.

4. D-215

Comment: The entire proposed standard has gone beyond Congressional intent.

5. D-114

Comment: Favor the high stack approach. Dispersion methods exist for lowering health hazard at less cost.

6. D-114

Comment: The entire regulation encourages prolonging the life of inefficient old plants.

7. D-113

Comment. A multi-strategy approach should be used for pollution control with less strict limits on each component of the approach.

8. D-225

Comment: The use of biomass fuel in a direct fired industrial combustion boiler may have some ramifications involving NSPS. No examples given.

9. D-302

Comment: EPA should not be allowed to tell industry what methods must be used to reduce emissions. This discriminates against free enterprise. Emission limits should be set and industry should be free to meet them any way it chooses.

10. D-454, D-572

Comment: Against the EPA proposed standard as inflationary to the manufacturing industry and in general.

11. D-631

Comment: The standard must be technology-forcing. Thus, the "best system of continuous emission reduction" must go beyond what is routinely available on commercial units. The proposed standard does not do this.

12. D-631

Comment: The dominant part of EPA's analysis during the selection of the "best system of continuous emission reduction" must be the determination of the performance of the best technology. Several court decisions make clear that economic considerations are entitled to only very limited weight. If EPA declines to require the use of some available control devices, the Agency must show clearly that their costs are "grossly disproportionate" to the health and environmental benefits they would provide. Both the EPA and DOE proposals emphasize the cost factors too strongly.

13. D-631

Comment: Section 111 requires each NSPS to control all significant pollutants from a source category. This standard must therefore adequately limit emissions of polycyclic organic matter (POM), trace metals, and radionuclides, which may pose significant health hazards.

14. D-631

Comment: The percentage reduction and the ceiling must independently be instruments of emission reduction, technology-forcing and growth promoting. EPA has proposed a minimum percentage reduction coupled with a ceiling that never requires reduction beyond the minimum percentage. In contrast, DOE would have EPA select a ceiling and then choose a percentage reduction that never achieves emissions lower than the ceiling. Both approaches would make one or the other part of the composite standard meaningless. This is not the intent of Congress.

15. D-491

Comment: EPA failed to recognize material differences among power plants as allowed by the Clean Air Act, as follows:

- Section 111(b)(2) of the Act says the Administrator "may distinguish among classes, types and sizes within categories of new sources" for the purpose of establishing standards (emphasis added).
- Section 111(b) of the Act, prior to the 1977 amendments, also allowed EPA to establish different standards for different classes or types of facilities
- the 1977 amendments did not affect the ability to subcategorize various classes, types and sizes of utilities.

16. D-491

Comment: In developing the standard EPA did not strike the proper balance among emissions reductions, costs, energy impacts, and non-air health and environmental impacts.

17. D-491, F-1u

Comment: Under the terms of Section 113 of the Clean Air Act, the revised NSPS will have the force of a substantive criminal statute defining feloneous conduct. Under "due process of law" concepts the emission limitation, the percentage reduction requirement and the means for compliance determination must be unambiguous and achievable. EPA's failure to adhere to this principle might well render the standard unconstitutional.

18. D-491

Comment: Section 111(a)(1) of the Clean Air Act requires that each new source performance standard be "achievable." This, in turn, hinges on whether the entire system in question has been adequately demonstrated. Adequate demonstration applies both to the emission control system and the compliance determination system (i.e., compliance testing and continuous monitoring). The supporting material to the proposed NSPS does not adequately demonstrate that either emission control systems or compliance determination systems are state-of-the-art for long term day-to-day operation on large utilities. Thus, the proposed standard is illegal under section 111(a)(1) of the Act.

19. D-515

Comment: Against the location of any coal-fired plant in the San Joaquin Valley.

20. D-519

Comment: Numerous conflicts are present between the various contractor reports on technical issues. These conflicts indicate a weak data base and poor evidence for setting the standards (Explicit comparisons are given in comment).

21. D-629, D-634

Comment: Finds no substantive environmental gains or differences among any of alternatives analyzed and therefore recommends adopting DOE proposal on economic grounds. Wishes, however, that the option selected should protect midwestern coal production.

22. D-702, D-716, D-726, D-727

Comment: Requests that the proposed standards be given a thorough risk analysis and economic evaluation.

2.12 Comments Not Addressing the Proposed Standard

D-15, D-38, D-43, D-65, D-117, D-157, D-203, D-230, D-328, D-338, D-408, D-484, D-529, D-534, D-536, D-581, D-586, D-594, D-603, D-604, D-636, D-638, D-656, D-661, D-664, D-665, D-671, D-707, D-743

2.13 Comments Duplicating Previous Submissions

D-527, D-528, D-530, D-535, D-543, D-544, D-550, D-553, D-555, D-560, D-557, D-559, D-563, D-596, D-580, D-589, D-591, D-597, D-615, D-617, D-618, D-619, D-649, D-650, D-652, D-654, D-655, D-658, D-662, D-669, D-672, D-676, D-677, D-679, D-680, D-681, D-685, D-686, D-687, D-689, D-690, D-699, D-700, D-727, D-732, D-742, D-745, D-746, D-752, D-754, H-9.

These comments fall into one of two categories:

- A duplicate of a previous submission usually transmitted through an alternate channel such as a Senator, Representative or the President's office.
- A defacto duplicate containing minor corrections or clarifications. Any resubmission containing major substantive new material was treated as a separate comment and is not recorded here.

3. SULFUR DIOXIDE

3.1 INTRODUCTION

On September 19, 1978, EPA proposed standards for control of sulfur dioxide emissions from power plants. Although a uniform SO_2 control requirement was proposed, the Administrator specifically noted that no final decision had been reached and that a number of alternatives were being considered. A summary of impacts for the alternatives under consideration at that time was presented in the preamble to the proposal (43 FR 42165) and in the Supplement to the document "Electric Utility Steam Generating Units, Background Information for Proposed SO_2 Emission Standards" (EPA-450/2-78-007a-1). On December 8, 1978, EPA provided analyses of additional alternatives under consideration (43 FR 57834). Further analyses of the most recent alternatives considered are contained within the preamble to the promulgated regulations and in the docket.

Since proposal, additional technical data describing flue gas desulfurization system performance has been collected. EPA has collected information on the performance of dry control systems and has placed this material in the docket. A summary of dry control system performance is given in the preamble to the final regulations. A more detailed report on the performance of dry control systems and their economic, environmental, and energy impacts is given in section 3.4 of this document.

Additional data on the performance of wet scrubber sulfur dioxide control systems has also been collected. These tests followed the initial data collection effort contained in the EMB Report 77 SPP 23A (August 1978) that were described in the Background Information Document for proposal (EPA-450/2-78-007a-1). The results of these FGD performance tests are presented in two test reports.

Test report A contains the results of monitoring the performance of FGD systems at (1) the Columbus and Southern Ohio Electric Company's Conesville Station, (2) the Tennessee Valley Authority's (TVA) Shawnee Station, and (3) the Northern Indiana Public Service Company's (NIPSCO) Mitchell Station. Test Report B contains the results of monitoring units at Kansas Power and Light Company's Lawrence Station and additional tests at TVA's Shawnee Power Station. Testing was also attempted at Kansas City Power and Light Company's LaCygne Station, but testing was not feasible due to boiler outages.

3.2 PERFORMANCE TEST REPORT A

This test report includes results of monitoring the following FGD systems:

1. At the Conesville No. 5 plant of Columbus and Southern Ohio Electric Company, EPA gathered continuous SO_2 data for the period from July to December 1978. During the test period, data for only 34 days were gathered due to frequent boiler and scrubber outages. The Conesville system averaged 88.8 percent SO_2 removal. Outlet SO_2 emissions averaged 0.80 lb/million Btu.

2. The performance of the Wellman-Lord FGD unit at NIPSCO's Mitchell station was monitored during 1978, including 1 41-day continuous period of operation. Data from this period were combined with previous data and analyzed; averaging 0.61 lb/SO_2/million Btu and 89.2 percent SO_2 removal for the 56-day test period.

3. From December 1978 to February 1979, EPA gathered continuous SO_2 data from the 10 MW prototype unit at TVA's Shawnee station using a TCA absorber with lime. Forty-two 24-hour periods of data were obtained when 3.0 percent sulfur coal was fired. SO_2 removal averaged 88.6 percent.

Due to the intermittant operation of the Conesville unit which had started up in June shortly before EPA began monitoring performance and which was undergoing shakedown of the equipment, much of the data were collected during periods when the operation had not completely stabilized. For this reason, the variability of data for this unit was higher when compared to the data for the other two units tested at NIPSCO and TVA's Power Stations.

At the Conesville and TVA installations, SO_2 and O_2 concentrations were measured upstream and downstream of the FGD system using continuous instrumental monitors. Copies of boiler operation logs and FGD system operation logs were obtained to document process operating conditions during the monitoring periods. At the Wellman-Lord demonstration site, a wealth of information is being generated including CO_2, O_2, H_2O, SO_2, and coal analyses. The mass emission data was submitted by the EPA contractor based upon a combination of these data to produce the most accurate results on a mass basis.

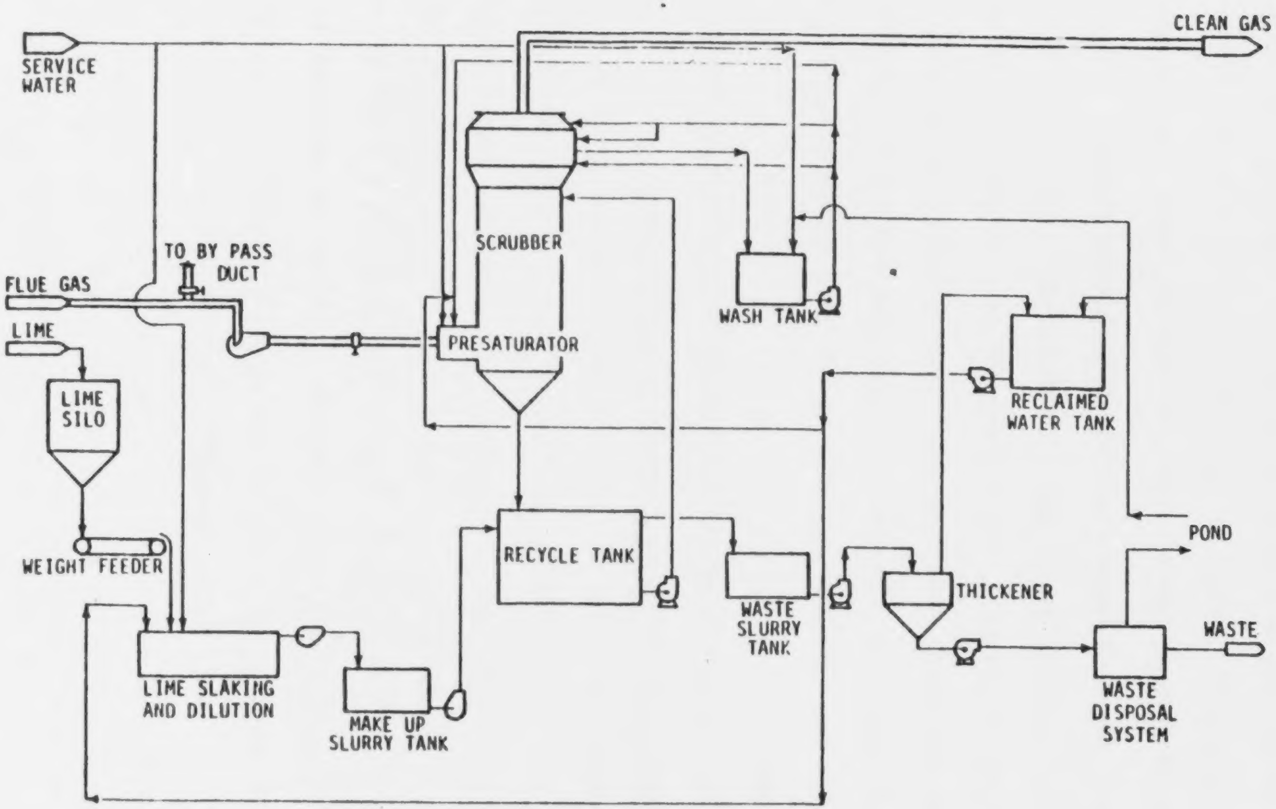
As in all cases, the instruments (except NIPSCO) used to generate data have been subjected to the appropriate test procedures (Federal Register, Vol. 40:194, October 6, 1975) to assure accuracy of all data reported herein.

3.2.1 Description of Test Sites

3.2.1.1 Conesville Unit No. 5.,Columbus and Southern Ohio Electric Company

Conesville Generating Unit 5 is a coal-fired unit rated at a net capacity of 375 MW. The steam generator is a Combustion Engineering controlled circulation, single reheat, balanced draft boiler with a primary steam flow of 3,130,000 pounds per hour at 2620 psig, 1005°F. The turbine generator is nominally rated at 403 MW. The fuel supply is raw (unwashed) coal as delivered direct from the mine. Typical coal analysis is 14.0 - 16.0 percent ash, 3.5 - 4.5 percent sulfur, with a high heating value of 10,400 to 10,800 Btu/per pound.

The flue gas passes from the boiler to a cold side electrostatic precipitator (Research-Cottrell, weighted-wire, 99.65 percent design particulates removal), induced draft fans, and then to either the flue gas desulfurization system or the full-flow bypass before final exhaust through an 800 fot acid-resistant, brick-lined stack. See Figure 3-1.


SERVICE WATER
CLEAN GAS
FLUE GAS
TO BY PASS DUCT
LIME
SCRUBBER
WASH TANK
PRESATURATOR
LIME SILO
RECLAIMED WATER TANK
WEIGHT FEEDER
RECYCLE TANK
POND
WASTE SLURRY TANK
THICKENER
WASTE
LIME SLAKING AND DILUTION
MAKE UP SLURRY TANK
WASTE DISPOSAL SYSTEM

Columbus and Southern Ohio Electric, Conesville No. 5 FGD System:
Process Flow Diagram.

Figure 3-1

The FGD system consists of two mobile-bed scrubber modules furnished by the Air Correction Division of Universal Oil Products. Each module is designed to handle 60 percent of the total full-load flue gas flow (total flow - 1,202,271 cfm at 286°F) with a minimum SO_2 removal efficiency of 89.6 percent. The flue gases are contacted countercurrently in a single stage spherical-packing mobile bed with thiosorbic lime slurry. The scrubber effluent slurry is recycled with a bleed-off to a thickener. The thickener concentrates the solids from 9 percent to approximately 30 percent solids. The thickener underflow is pumped to a treatment plant for sludge fixation and disposal. The thickener overflow is recycled to the scrubber presaturator and lime slaker.

The Unit 5 scrubbers were placed in service in February 1977.

3.2.1.2 Shawnee FGD Prototype, Tennessee Valley Authority

The Shawnee Power Station, operated by the Tennessee Valley Authority (TVA), is a coal-fired steam generation station having 10 turbines, each served by a boiler and stack. A portion of the exhaust gases from one of these stacks is directed for use with three pilot plant scale wet scrubbers systems - a venturi with a spray tower after absorber, a turbulent contact absorber (TCA), and a marble bed absorber. Testing was performed on the venturi/spray tower using limestone enhanced with adipic acid and the TCA using lime only. This report describes the test and results for the TCA/lime system.

The venturi system was manufactured by Chemical Construction Company in the late 1960's and contains an adjustable throat which permits control and variation of pressure drop. The TCA unit, constructed by Universal Oil Products, uses a fluid bed of low density plactic spheres that migrate between retaining grids. The marble-bed absorber is no longer operated.

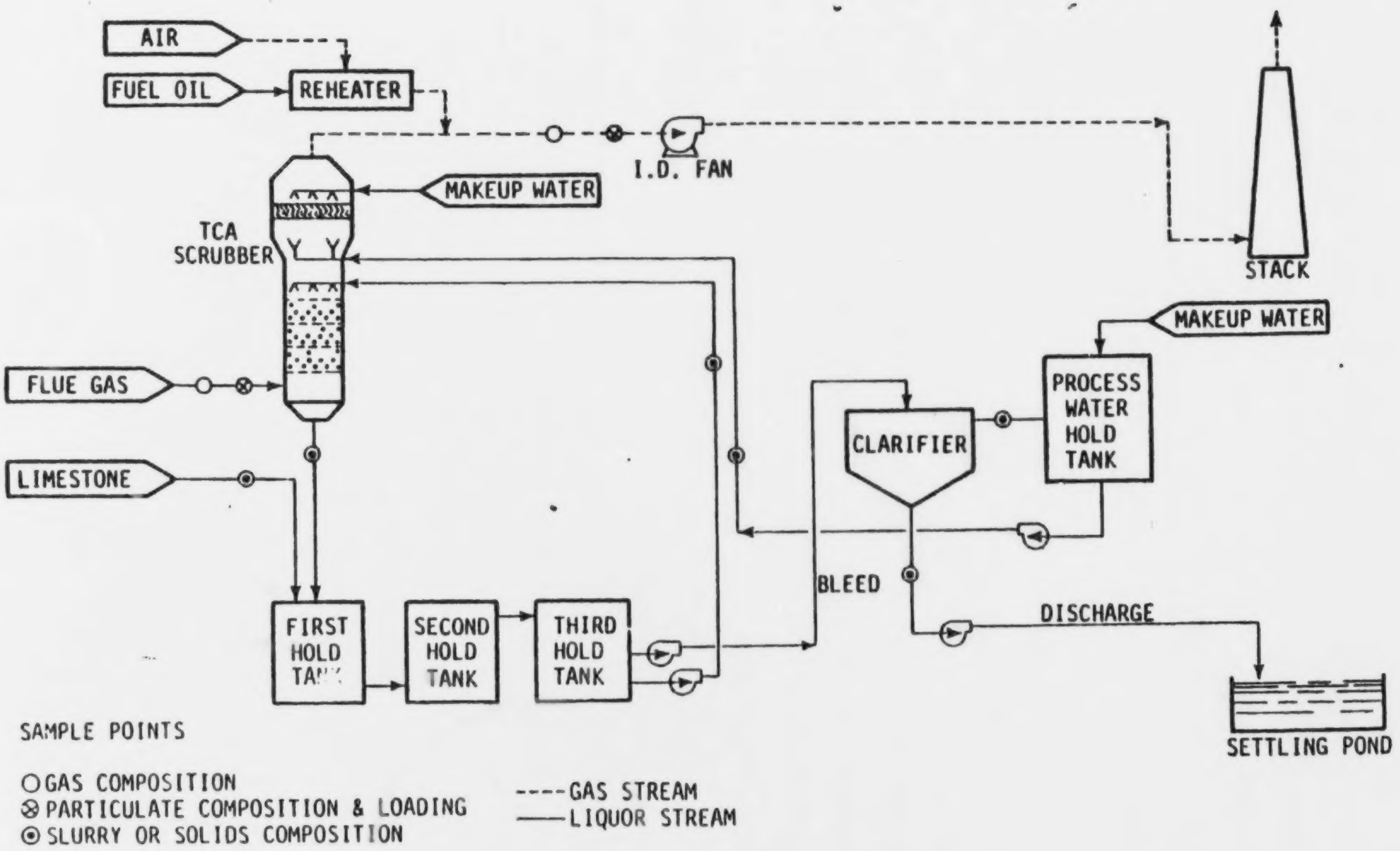
Figure I-2 is the process flow diagram for the Shawnee TCA/lime system.

3.2.1.3 Mitchell No. 11, Northern Indiana Public Service Company

The D.H. Mitchell No. 11 boiler is a balanced draft, wet bottom radiant wall-fired reheat boiler manufactured by Babcock and Wilcox. The maximum rated output is 115 megawatts. Service began in 1969. Detailed boiler characterization may be found in EPA 600/7-77-014, dated February 1977.

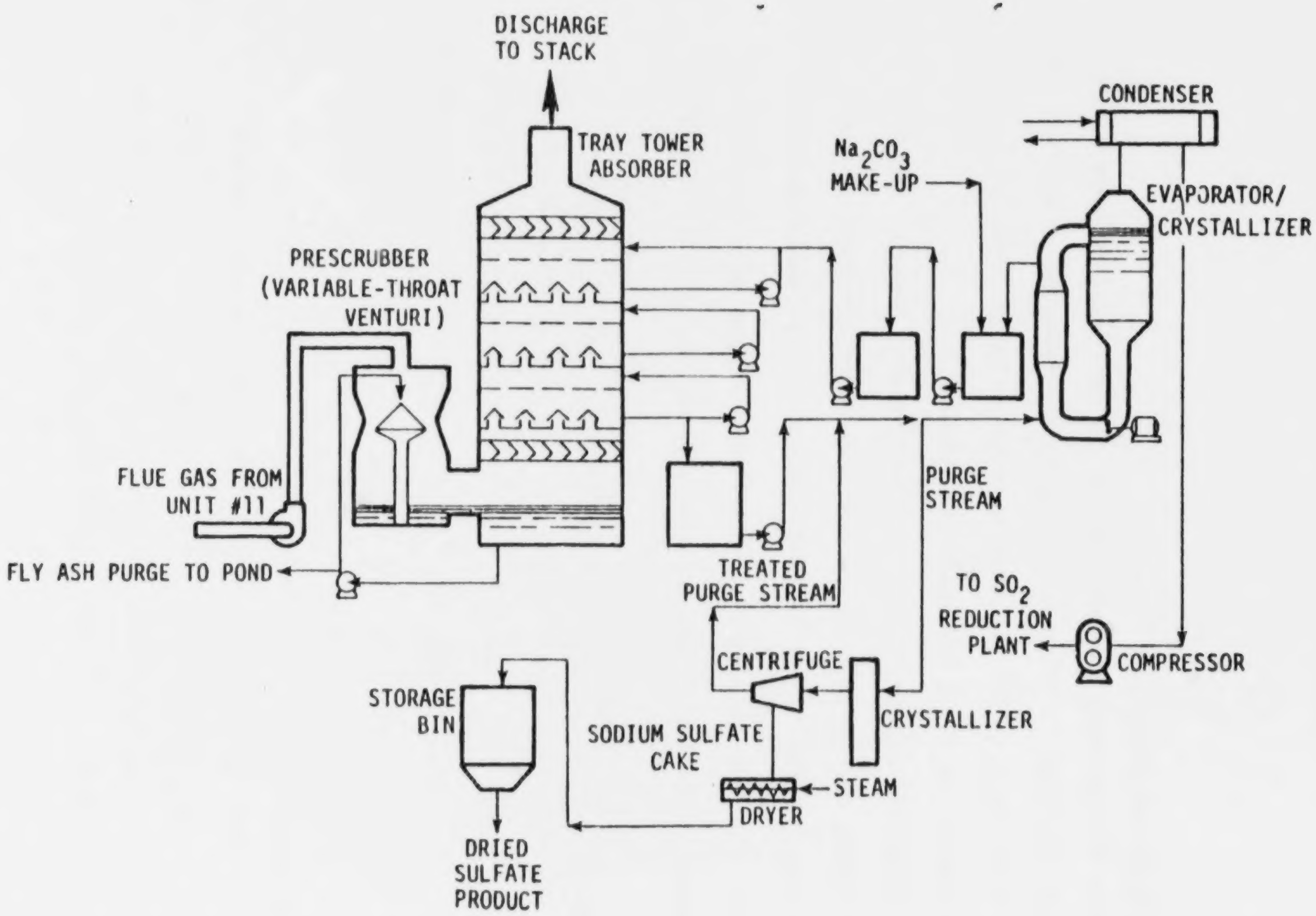
The Wellman-Lord FGD system (Figure 3-3) consists of three major operating sections - SO_2 absorption, purge treatment and SO_2 regeneration. In the SO_2 absorption sectum, residual fly ash in the flue gas is removed by a wet scrubber. SO_2 is then removed by scrubbing with a sodium sulfite solution. The scrubber purge helps maintain inactive sulfates and their sulfates at tolerable levels in the sodium solution.

The absorbed SO_2 is thermally regenerated to release SO_2 as a concentrated gas stream and enable the reconstituted scrubbing solution to be recycled to the absorber. The concentrated SO_2 is converted to elemental sulfur at Mitchell No. 11 as shown in Figure 3-3 by the Allied SO_2 reduction process using natural gas and a Claus sulfur recovery system. Claus tail gas is incinerated and recycled to the flue gas upstream of the absorber.


AIR
FUEL OIL
REHEATER
I.D. FAN
MAKEUP WATER
TCA SCRUBBER
STACK
MAKEUP WATER
FLUE GAS
PROCESS WATER HOLD TANK
CLARIFIER
LIMESTONE
BLEED
DISCHARGE
FIRST HOLD TANK
SECOND HOLD TANK
THIRD HOLD TANK
SETTLING POND
SAMPLE POINTS
○ GAS COMPOSITION
⊗ PARTICULATE COMPOSITION & LOADING
⊙ SLURRY OR SOLIDS COMPOSITION
---- GAS STREAM
—— LIQUOR STREAM

Tennessee Valley Authority,
Shawnee No. 10 Prototype Test Unit:
General Process Diagram.

Figure 3 -2


DISCHARGE TO STACK
TRAY TOWER ABSORBER
CONDENSER
Na_2CO_3 MAKE-UP
EVAPORATOR/ CRYSTALLIZER
PRESCRUBBER (VARIABLE-THROAT VENTURI)
FLUE GAS FROM UNIT #11
FLY ASH PURGE TO POND
PURGE STREAM
TREATED PURGE STREAM
TO SO_2 REDUCTION PLANT
COMPRESSOR
CENTRIFUGE
STORAGE BIN
CRYSTALLIZER
SODIUM SULFATE CAKE
STEAM
DRYER
DRIED SULFATE PRODUCT

Northern Indiana Public Service,
D. H. Mitchell No. 11 Wellman Lord/Allied System:
General Process Diagram.

Figure 3-3

3.2.2 Data Gathering Systems

The sulfur dioxide monitoring equipment at all test locations were DuPont 460 Photometric Analyzers.[1] The basic instrument configuration varied from site to site and is discussed in the following narrative. Typical sampling locations are shown in Figure 3-4 for a two module FGD system.

Oxygen monitoring equipment varied from site to site; however, the basic detection principle was the same. The oxygen measurement equipment is also described in detail below. Continuous instrumental moisture measurements were not performed. The moisture contents of the sample streams were determined by manual procedures. The test procedures used at each location are described as follows:

3.2.2.1 Conesville No. 5, Columbus and Southern Ohio Electric Company

Figure 3-5 illustrates the DuPont 460 SO_2 analyzer and Thermox WDG III oxygen analyzer scheme used at Conesville No. 5. The gas sample was extracted from the stack through a 30 micron metal filter element and a heat traced teflon sample line. The sample probes were equipped with electrically operated three-way values for automatic high pressure air back purge of the filter element, and for remote injection of calibration gas to the sample line/analyzer system. Oxygen was determined with a Thermox WDG III zirconium oxide-cell analyzer. The sample for oxygen analysis was withdrawn from the SO_2 analyzer, so that SO_2 and O_2 were measured in the same gas stream. The operating cycle of the analyzer was 10 minutes. During this period there were approximately

---

[1] Mention of a specific company or product name does not constitute endorsement by the Environmental Protection Agency.

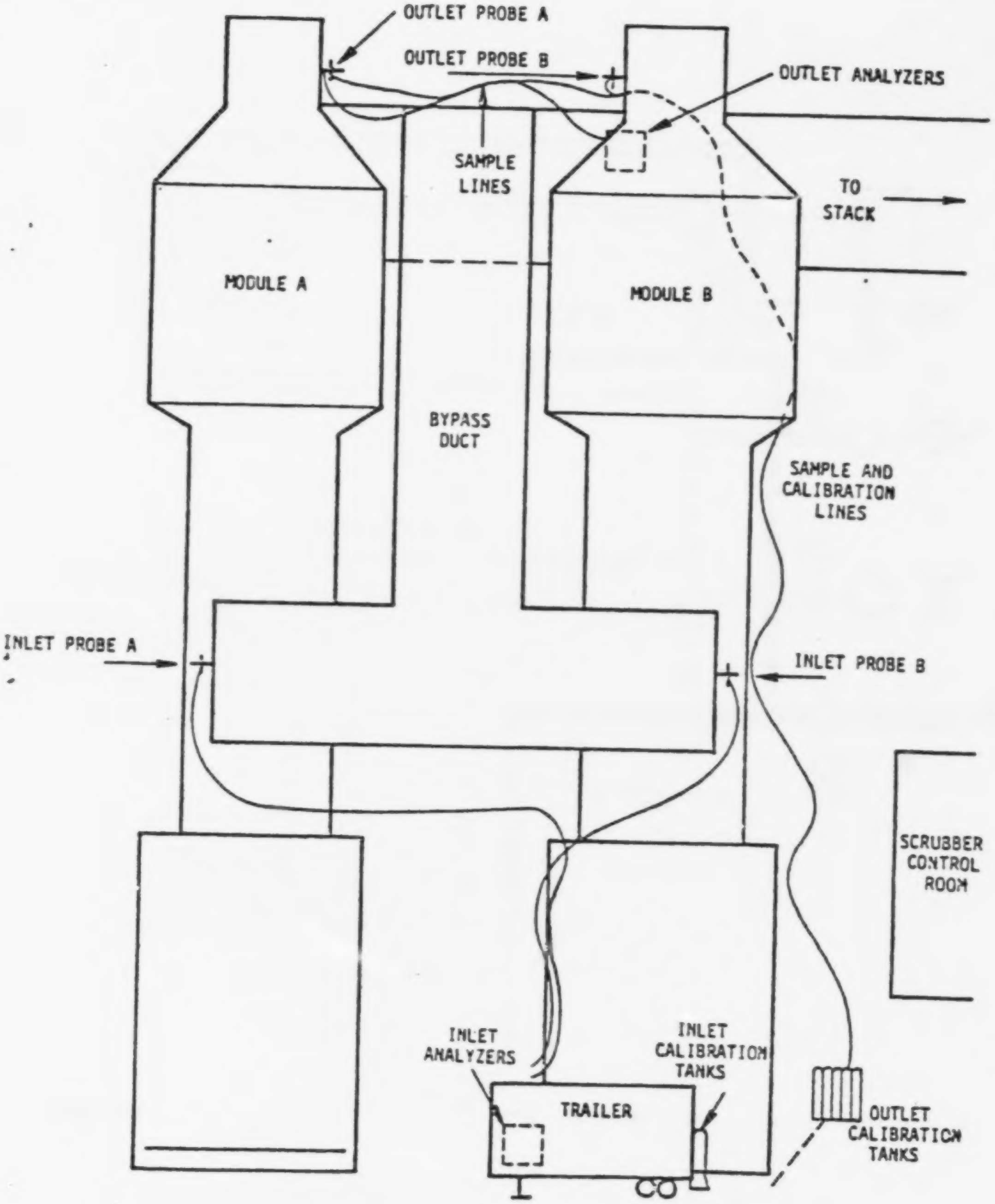

OUTLET PROBE A
OUTLET PROBE B
OUTLET ANALYZERS
SAMPLE LINES
TO STACK
MODULE A
MODULE B
BYPASS DUCT
SAMPLE AND CALIBRATION LINES
INLET PROBE A
INLET PROBE B
SCRUBBER CONTROL ROOM
INLET ANALYZERS
INLET CALIBRATION TANKS
TRAILER
OUTLET CALIBRATION TANKS

Figure 3-4. Typical Scurbber Sampling Locations

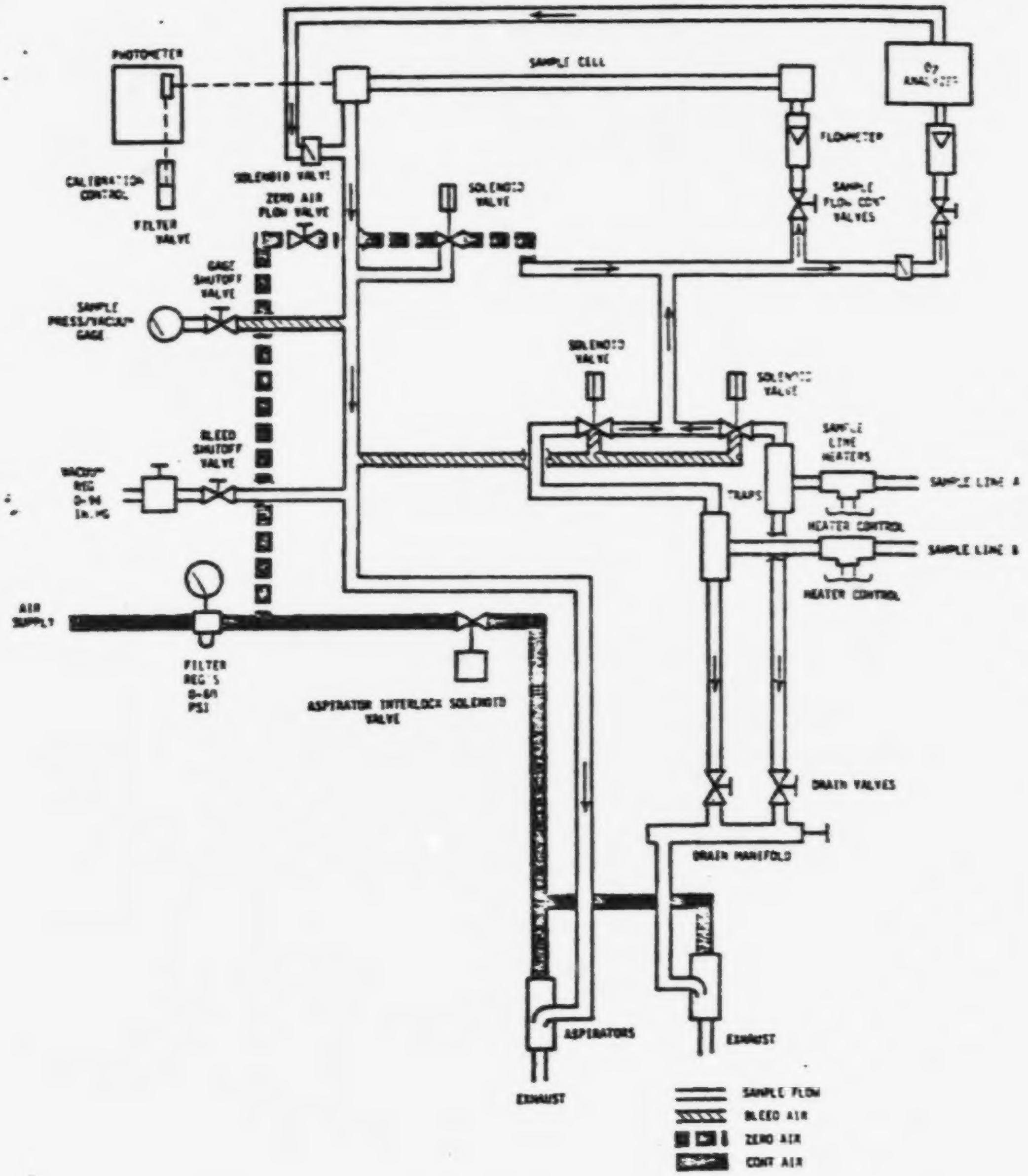

PHOTOMETER
SAMPLE CELL
O2 ANALYZER
FLOWMETER
CALIBRATION CONTROL
FILTER VALVE
SOLENOID VALVE
ZERO AIR FLOW VALVE
SOLENOID VALVE
SAMPLE FLOW CONT VALVES
GAGE SHUTOFF VALVE
SAMPLE PRESS/VACUUM GAGE
SOLENOID VALVE
SOLENOID VALVE
BLEED SHUTOFF VALVE
VACUUM REG 0-30 IN.HG
SAMPLE LINE HEATERS
TRAPS
SAMPLE LINE A
HEATER CONTROL
SAMPLE LINE B
HEATER CONTROL
AIR SUPPLY
FILTER REG'S 0-60 PSI
ASPIRATOR INTERLOCK SOLENOID VALVE
DRAIN VALVES
DRAIN MANIFOLD
ASPIRATORS
EXHAUST
EXHAUST
SAMPLE FLOW
BLEED AIR
ZERO AIR
CONT AIR

Figure 3-5. Instrument System Schematic-Conesville No. 5

4 1/2 minutes of sample analysis and 1/2 minute of automatic zero and probe backflush for each of the two sample points. The SO_2 analyzer output was recorded on a two pen recorder, and the O_2 analyzer output was recorded on a single pen recorder.

The outlet analyzer system was identical except that the measurement range for SO_2 was 0-1000 ppm.

Moisture data were collected using manual procedures. At approximately weekly intervals, samples were collected using either drying tubes or condenser techniques at the inlet and outlet ducts, and also after the condensate separator is the SO_2 analyzer. The sample stream temperature at each condensate separator was recorded daily. The sample stream moisture contents were assumed (and confirmed by manual tests) to be saturated at the average condensate trap temperatures for generally, a week-long inteval.

Copies of the daily FGD system operator's log were collected along with daily instrument logs and instrument operation and calibration data sheets.

3.2.2.2 Shawnee 10A and 10B, Tennessee Valley Authority.

A schematic diagram of the monitoring system used at each of the four monitoring locations is shown in Figure 3-6. The sulfur dioxide (SO_2) instrument at each location is a DuPont 460 analyzer. The oxygen (O_2) analyzer is a Thermox model WDG 3 instrument. The ranges of the scrubber inlet SO_2 analyzers are set at 0-4000 ppm SO_2 and the ranges of the two scrubber outlet SO_2 analyzers are 0-1000 ppm. The ranges of O_2 analyzer are all set at 0-10 percent O_2. The SO_2 and O_2 probes tips are located at the stack centers with the O_2 probe approximately 1 stack diameter upstream of the SO_2 probe at

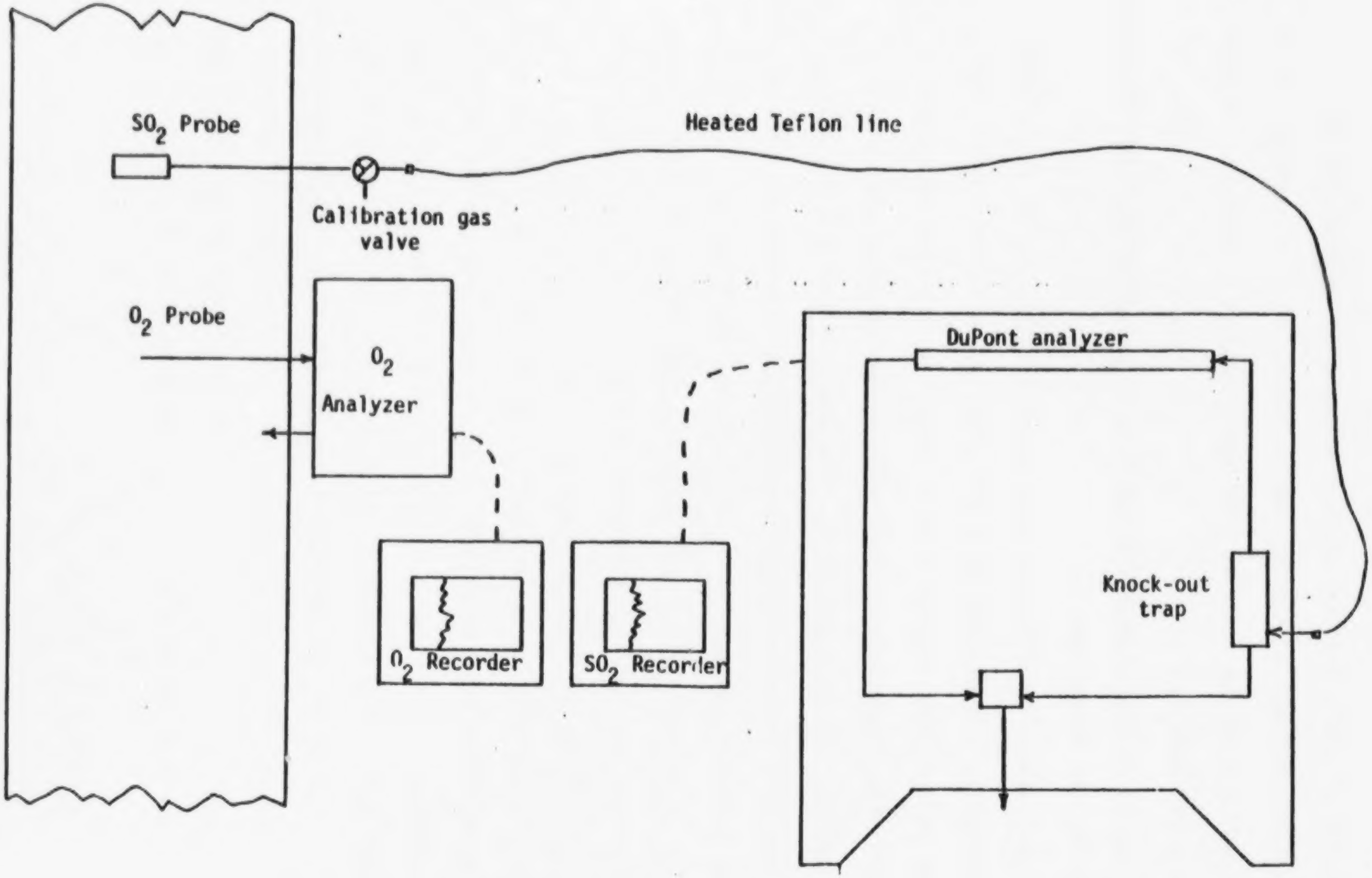

SO_2 Probe
Heated Teflon line
Calibration gas valve
O_2 Probe
O_2 Analyzer
DuPont analyzer
Knock-out trap
O_2 Recorder
SO_2 Recorder

Figure 3-6. Instrument System Schematic, Shawnee Power Station.

each of four locations. The analyzers operate on approximately 8-minute cycles during which stack gas concentration measurements are made continuously except for an automatic 1-minute backflush period. Concentration measurements are recorded continuously on four strip chart recorders located in the scrubber control room.

The moisture content correction for the SO_2 gas measurements was determined from the temperature measurement in the sample gas stream immediately following the knock-out trap in the analyzer case. This gas was assumed saturated at this temperature. The moisture content correction for the O_2 gas measurements was the stack moisture content as the O_2 analyzers measured a wet gas stream.

3.2.2.3 Mitchell No. 11, Northern Indiana Public Service Company

(The information on the gas sampling and analysis procedures at Mitchell No. 11 were not received in time to incorporate in this report and will be added when the final report on SO_2 monitoring at power plants is issued by EPA).

3.2.3 Data Reduction Procedures

The types of data that were collected for reduction purposes were:

inlet SO_2 strip chart (2 inlets)
inlet O_2 strip chart (2 inlets)
outlet SO_2 strip chart (2 outlets)
outlet O_2 strip chart (2 outlets)
scrubber logs (including boiler load and coal feed rate)
instrument logs
instrument calibration data sheets
manual test results

The data were first logged in as received and then were reviewed for possible data gaps. The charts were then transcribed to a tabular format using a strip chart data digitizer. The tabular data were then processed through a manual keypunch operation so that appropriate scale factors, moisture values, process data, and descriptive comments could be included prior to data listing. The punched cards were then processed by computer to obtain a data listing and calculated results for each 15 minute data point. The data listings were reviewed by the EPA contractor for keypunch or other transcription errors. The scrubber and instrument logs were reviewed so that periods of boiler outage, scrubber outage, bypass, startup or shutdown could be properly identified and coded so that these data would not be included in the calculation of averages and summaries.

After data editing was completed, average summaries were prepared. Averages based on the 15-minute data were prepared for consecutive 1-hour, 3-hour, 8-hour, and 24-hour intervals. In order to calculate an average result for a single interval, it was specified that at least 75 percent of the 15-minute data points be available for that interval. For example, an 8-hour average could only be calculated when 24 of the possible 32 15-minute data points were available. When less than 75 percent of the data were available for an interval, an average was not calculated and blanks were entered in the summary printouts.

After each 30 days of average interval data, a statistical summary was prepared to determine the following parameters for the average.

mean

average deviation

minimum

percent standard deviation

standard deviation

maximum

range

These parameters were calculated assuming the data were normally distributed.

The calculation procedures used to convert the analyzer outputs for sulfur dioxide and oxygen concentrations to mass emission factors are given in 40 CFR 60 Subpart D. This procedure is known as the F-factor approach and is outlined below:

$$E = \frac{CFK}{1-M} \times \frac{20.9}{\frac{20.9-O_2}{1-M}}$$

Where E = Emission factor - lb/million Btu

C = SO_2 concentration - ppmv, wet basis

F = Stoichiometric conversion factor, 9820 dscf/million Btu for subbituminous coal

K = Conversion factor, 1.659×10^{-7} lb/dscf per ppmv

O_2 = Oxygen concentration, percent by volume as measured

M = Moisture fraction as measured (for dried samples, $M=0$)

The sulfur dioxide and oxygen concentration results were obtained by multiplying the strip chart readings as a percent of scale by the appropriate calibration factor.

The emission factor was calculated for each FGD system inlet and outlet test point. The sulfur dioxide removal efficiency for a module is calculated by:

$$\text{Efficiency} = \frac{\text{Ein} - \text{E out}}{\text{Ein}} \times 100 \text{ percent}$$

When more than one inlet and/or outlet test point was monitored, the total system emission factors and sulfur dioxide removal efficiencies were calculated by a weighted average procedure. The equation for this calcualtion for total system efficiency is given by:

$$\text{EFF total} = \text{EFF}_A\ (F_A) + \text{EFF}_B(F_B)$$

Where,

$\text{EFF}_{\text{total}}$ = total system efficiency

EFF_A = efficiency of module or module set A

F_A = fraction of gas flow through module or module set A

EFF_B = efficiency of module or module set B

F_B = fraction of gas flow through module or module set B

The only data for this report requiring the above approach was for Conesville No. 5. Since modular flow was not equal, mass balance procedures were developed to determine the gas flow rate through each module. The flow rate exiting each scrubber module was measured by plant equipment and was recorded on the scrubber logs. The bypass flow was estimated by calculating the total gas flow to the FGD system based on stoichiometric relationships and subtracting the flow through the modules. The total inlet flow was calculated based on scrubber outlet temperature, pressure and average moisture content. Since the bypass flow estimate is the difference between two large numbers, it is subject to significant error if any smaller errors are present in the inlet or module outlet results. Therefore, the total system performance data should not be used as precise results, and are presented for estimation purposes.

The equations used to calculate system performance are as follows:

Total inlet flow rate (calculated at outlet conditions)

$$V_t = 9820 \frac{1}{1-Mo} \frac{Ts}{530} \frac{29.92}{Ps} \frac{20.9}{20.9 - \%O_2/(1-Mm)} \frac{HR}{60}$$

Where V_t = total volume flow in FGD system at outlet conditions (cfm, wet)

9820 = stoichiometric combustion ratio, (scfm/10^6 Btu, dry)

Mo = FGD outlet moisture fraction

Ts = average outlet temperature (°F)

Ps = average outlet pressure (inches Hg)

$\%O_2$ = oxygen concentration measured at outlet (percent by volume)

Mm = analyzer moisture content, (volume fraction)

HR = heat input rate (10^6Btu/hour)

Due to the flow meter calibration factors and the consistency of measurements, the following assumptions can be made:

Ts = 120°F (annubar output basis)

Ps = 29.9 2"Hg(annubar output basis)

Mo - 0.115 (saturated at 120°F)

The equation then simplifies to

$$V_t = \frac{\frac{4229.8(Hr)}{20.9 - \%O_2}}{1-Mm} \qquad \text{cfm, wet}$$

The heat input rate is the coal feed rate (lb/hr) which is recorded at hourly intervals on the scrubber log sheets, multiplied by an average of 10,500 BTU/lb (0.0105×10^6 Btu/lb)

The volume of flue gas bypassed is calculated by

$$V_{BP} = V_t - V_A - V_B$$

Where

V_{BP} = flow rate bypassed, cfm, wet, 120°F

V_A = flow from module A, cfm, wet, 120°F

V_B = flow from module B, cfm, wet, 120°F

The system emission rate is calculated as a flow-weighted total by:

$$E_s = \frac{V_A}{V_t} (E_{A\ out}) + \frac{V_B}{V_t} (E_{B\ out}) + \frac{V_{BP}}{V_t} \left(\frac{E_{A\ in} + E_{B\ in}}{2}\right)$$

Where:

E_s = system emission factor, $lb/10^6$ Btu

$E_{A\ out}$ = module A outlet emission factor, $lb/10^6$ Btu

$E_{B\ out}$ = module B outlet emission factor, $lb/10^6$ Btu

$E_{A\ in}$ = module A inlet emission factor, $lb/10^6$ Btu

$E_{B\ in}$ = module B inlet emission factor, $lb/10^6$ Btu

The system SO_2 removal efficiency is:

$$E_{FF} = \left[1 - \frac{E_s}{\frac{E_{A\ in} + E_{B\ in}}{2}} \right] \quad (100)$$

3.2.4 Data Analysis

3.2.4.1 Data Calculation Assumptions

In the previous SO_2 monitoring report, several assumptions were made due to direct oxygen or moisture readings being unavailable, which led to a maximum error level due to the assumptions of 3 percent in emissions and 0.5 percent in percent removal efficiency.

For the data to be described, the only assumptions made were for moisture on the NIPSCO Wellman-Lord system. For those data calculations moisture contents were estimated from available charts of moisture versus boiler load. No estimate of accuracy is readily available, however, the resulting error is less than described above and based upon the expected accuracy of the boiler charts used, error should be negligible.

3.2.4.2 Data Availability

Table 3-1 shows the data gathering breakdown for the three sites. The total days sampling time was ascertained, then the boiler and scrubber down time was subtracted to yield the net days available for scrubber performance data. Data for each one-hour period was compiled and 24-hour periods characterized as full data periods and partial data periods. "Full data" is defined as data obtained when the boiler/scrubber system operated 18 hours or more and 18 hours or more of monitor data was obtained within a calendar day. "Partial data" is defined as data obtained when the boiler/scrubber operated less than 18 hr/day and at least 75 percent of the monitor data was obtained during the operational period.

As shown in Table 3-1 the percentage data availability ranged from 33.3 percent total days at Conesville B module to 72.7 percent at Mitchell No. 11 for overall efficiency, where both inlet and outlet data were available. Partial days have not yet been analyzed at the Shawnee and Mitchell sites.

TABLE 3-1. CATEGORIZATION OF DATA

	Conesville No. 5						Shawnee TCA			Mitchell No. 11		
	Module A			Module B								
	Inlet	Outlet	Both Inlet & Outlet	Inlet	Outlet	Both Inlet & Outlet	Inlet	Outlet	Both Inlet & Outlet	Inlet	Outlet	Both Inlet & Outlet
Total Days	184	184	184	184	184	184	49	49	49	85	85	85
Boiler Down	22	22	22	22	22	22	0	0	0	0	0	0
Scrubber Down	-	102	102	-	99	99	0	0	0	-	0	0
Net	162	60	60	162	63	63	49	49	49	85	77	77
Full Data Days	105	36	24	94	36	21	42	42	42	64	64	64
Partial Data Days	5	14	14	5	12	15	N/A	N/A	N/A	N/A	N/A	N/A
% Data Available:												
Total Days	64.8	60.0	40.0	58.0	57.1	33.3	85.7	85.7	85.7	75.3	72.7	72.7
Partial Days	67.9	83.3	63.3	61.1	76.2	57.1	N/A	N/A	N/A	N/A	N/A	N/A

As in the first report, it is important to note that the monitoring systems used were the existing systems and do not necessarily reflect state of the art monitoring capabilities. The simultaneous collection of inlet and outlet data as shown in Table 3-1 are substantially less than expected for a properly installed and operated new system, as reflected in a recent letter to EPA from Texas Utilities.[2] In that letter, one year's operation of a new $SO_2/O_2/H_2O$ integrated system yielded 88 percent data availability with most outages due to strip chart recorder malfunctions or unavailability of replacement probes.

3.2.4.3 Statistical Analyses

In the initial report and this report SO_2 monitoring data were analyzed on the basis of 24-hour averages (3-hour and 8-hour averages were also addressed in the initial report). Graphical analyses were made for inlet SO_2, outlet SO_2, and percent SO_2 emitted (100 percent removal).

In this report percent SO_2 emitted (i.e., 100 percent SO_2 reduction) is used to describe statistical performance of FGD units.

Figures 3-7, 3-8, and 3-9 graphically describe FGD performance at Conesville No. 5. Figure 3-7 shows inlet SO_2 emissions average 7.50 lb/10^6 Btu with a geometric dispersion (GD) of 1.059. Figure 3-8 shows outlet emissions averaging 0.80 lb/10^6 Btu with a GD of 1.802. Percent SO_2 emitted in Figure 3-9 , averages 10.8 percent (89.2 percent recovery) with a GD of 1.801.

Performance of the Shawnee TCA/lime system is reflected in Tables 3-10 through 3-12. Inlet SO_2 in Table III-4 averaged 5.55 lb/10^6 Btu with a GD of 1.116. Outlet SO_2 (Table 3-11) figures were 0.64 lb/10^6 Btu average, 1.279 GD. Percent SO_2 emitted on the TCA scrubber (Table 3-12) averaged 11.4 percent (88.6 percent recovery) for 42 days with a GD of 1.204.

---

[2] Letter, R. White, Texas Utilities, Generating Co. to C. Sedman, EPA, dated January 16, 1979.

The Wellman-Lord system statistics are represented by Figures 3-13 through 3-15. Actually the statistics here represent two periods of performance, approximately one year apart, which have been combined to represent a longer statistical period. Inlet SO_2 averaged 5.70 lb/10^6 Btu

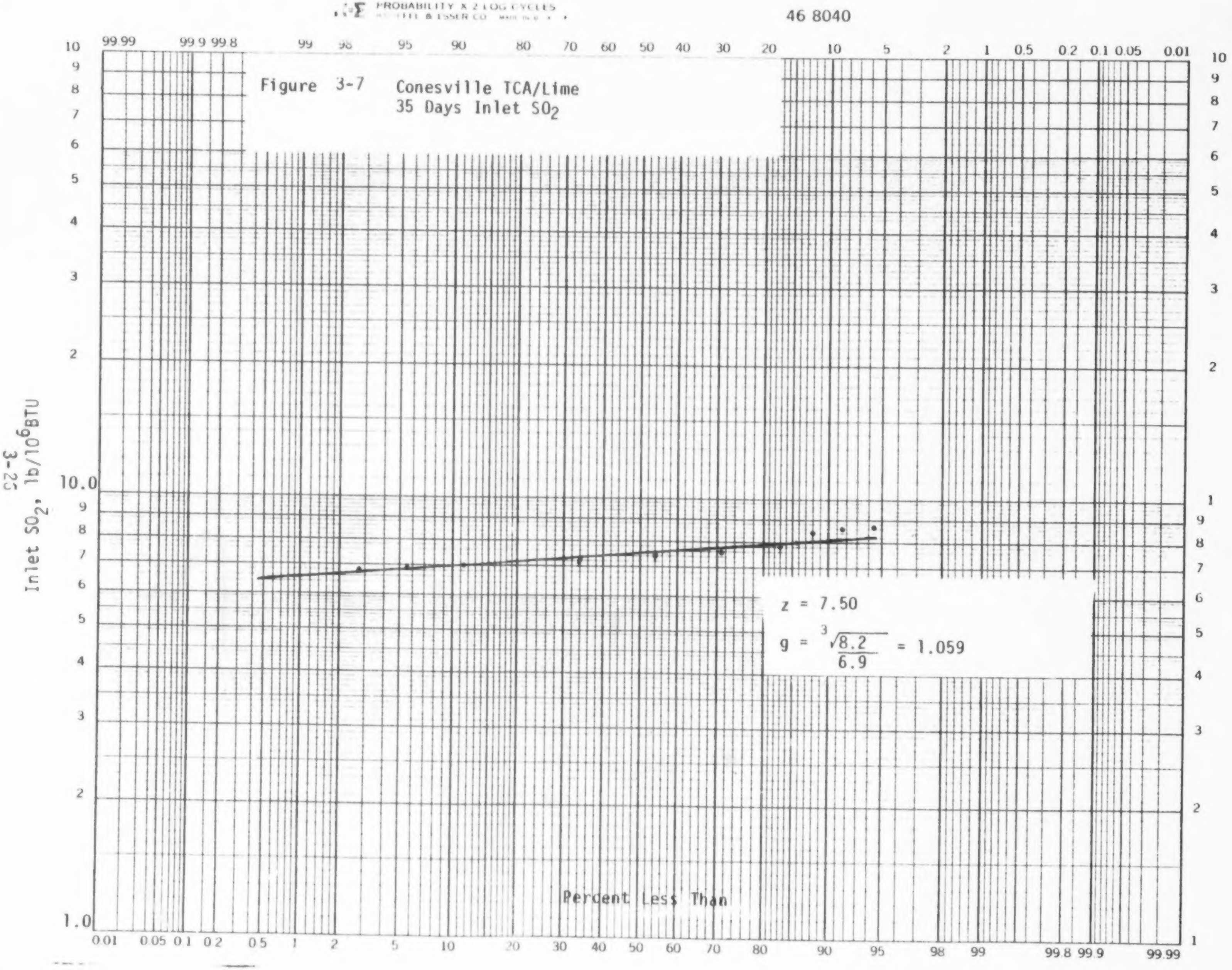


Figure 3-7 Conesville TCA/Lime
35 Days Inlet SO_2

$z = 7.50$

$$g = \sqrt[3]{\frac{8.2}{6.9}} = 1.059$$

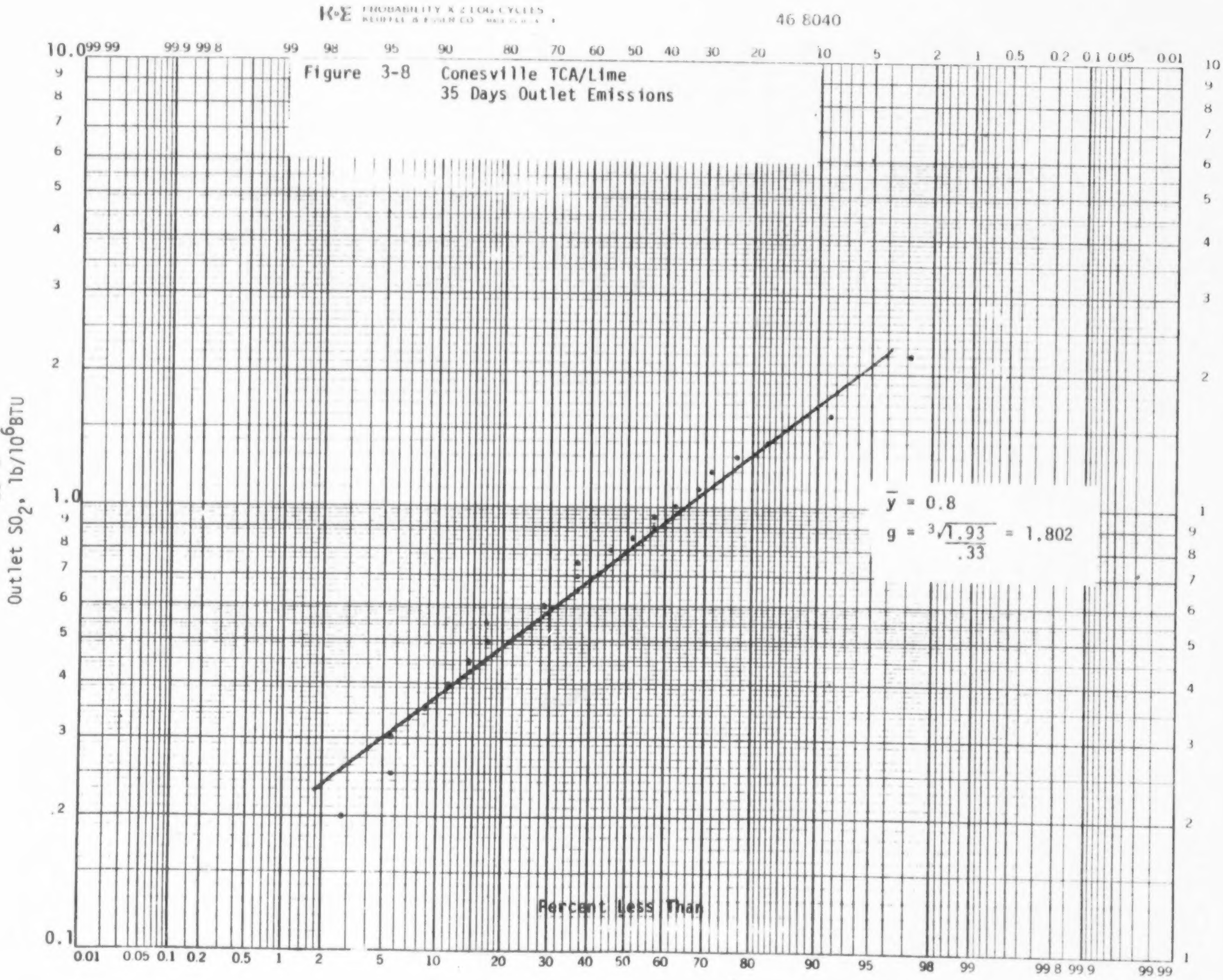


Figure 3-8 Conesville TCA/Lime
35 Days Outlet Emissions

$\overline{y} = 0.8$

$g = \sqrt[3]{\frac{1.93}{.33}} = 1.802$

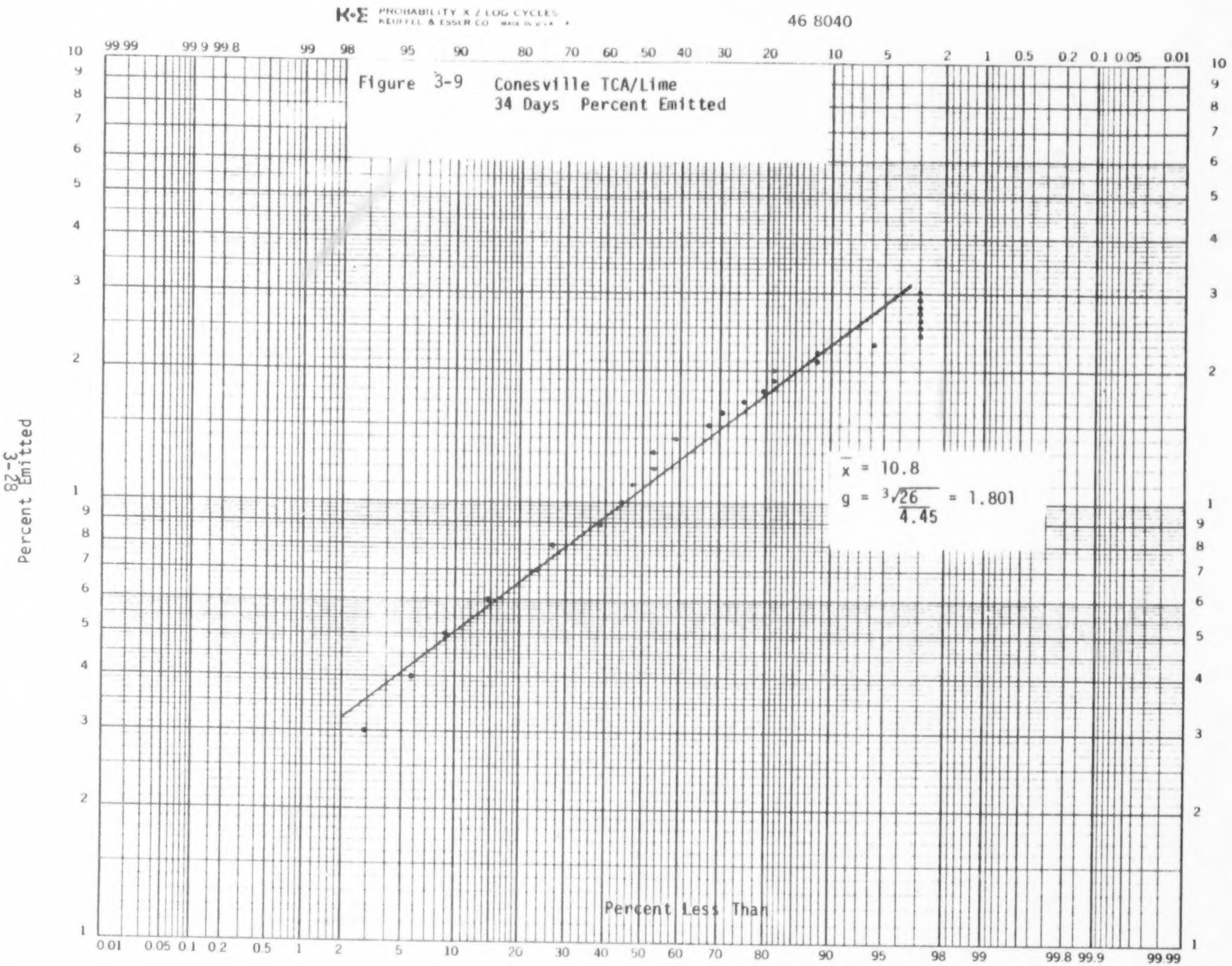


Figure 3-9 Conesville TCA/Lime
34 Days Percent Emitted

$\bar{x} = 10.8$

$g = \frac{^3\sqrt{26}}{4.45} = 1.801$

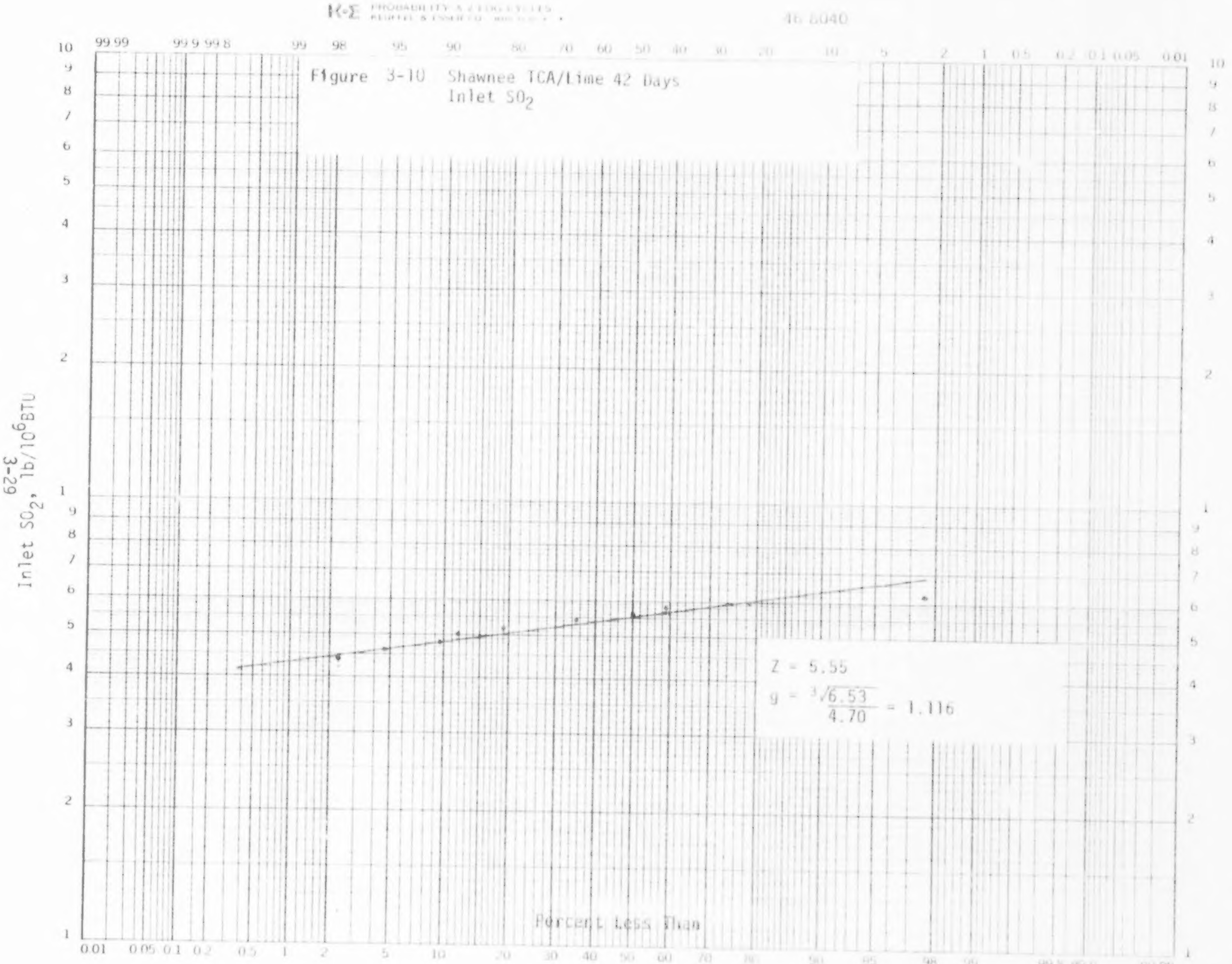


Figure 3-10 Shawnee TCA/Lime 42 Days
Inlet SO_2

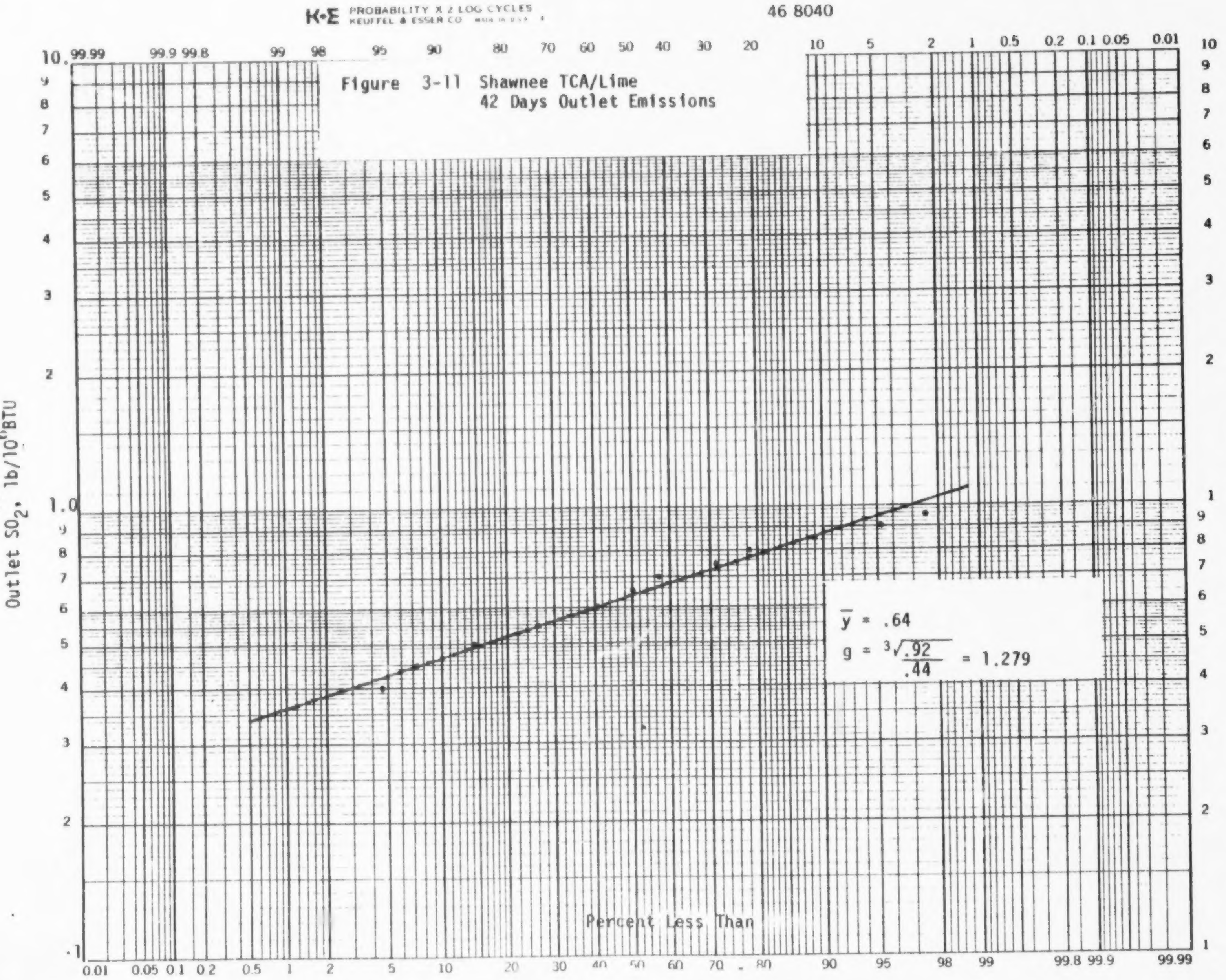


Figure 3-11 Shawnee TCA/Lime
42 Days Outlet Emissions

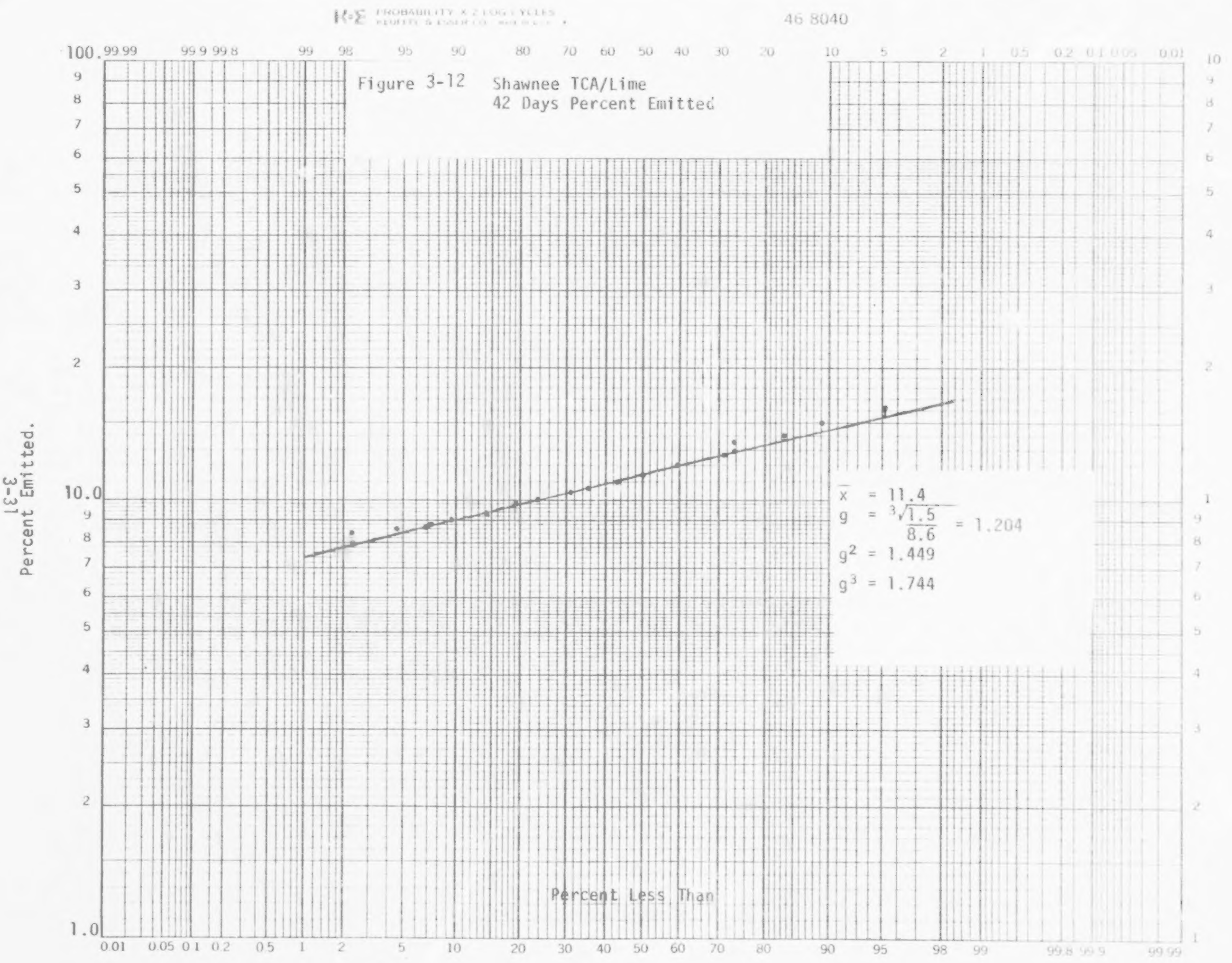


Figure 3-12 Shawnee TCA/Lime
42 Days Percent Emitted

$\bar{x} = 11.4$

$g = \sqrt[3]{\frac{1.5}{8.6}} = 1.204$

$g^2 = 1.449$

$g^3 = 1.744$

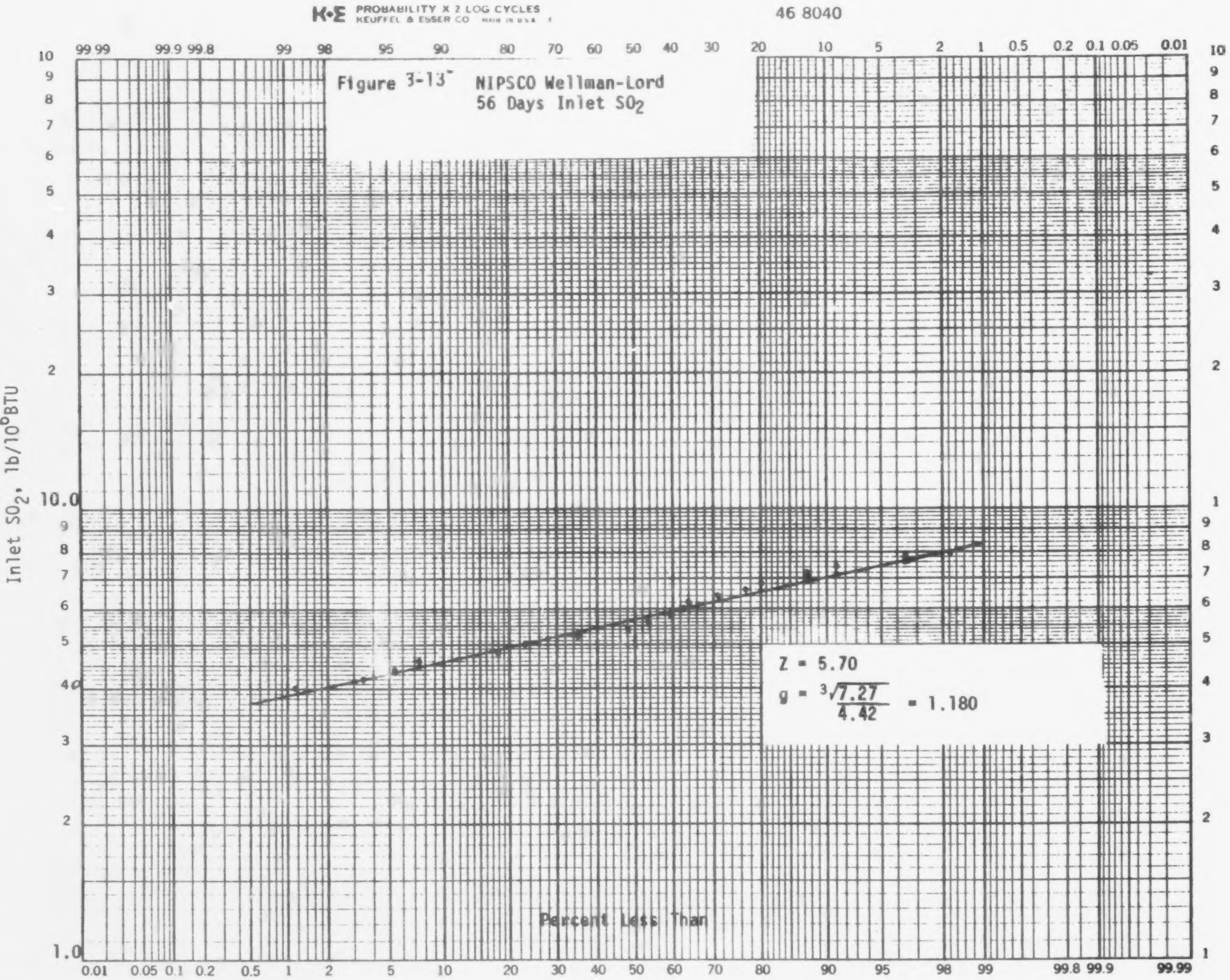


Figure 3-13 NIPSCO Wellman-Lord
56 Days Inlet SO_2

$Z = 5.70$

$g = \sqrt[3]{\frac{7.27}{4.42}} = 1.180$

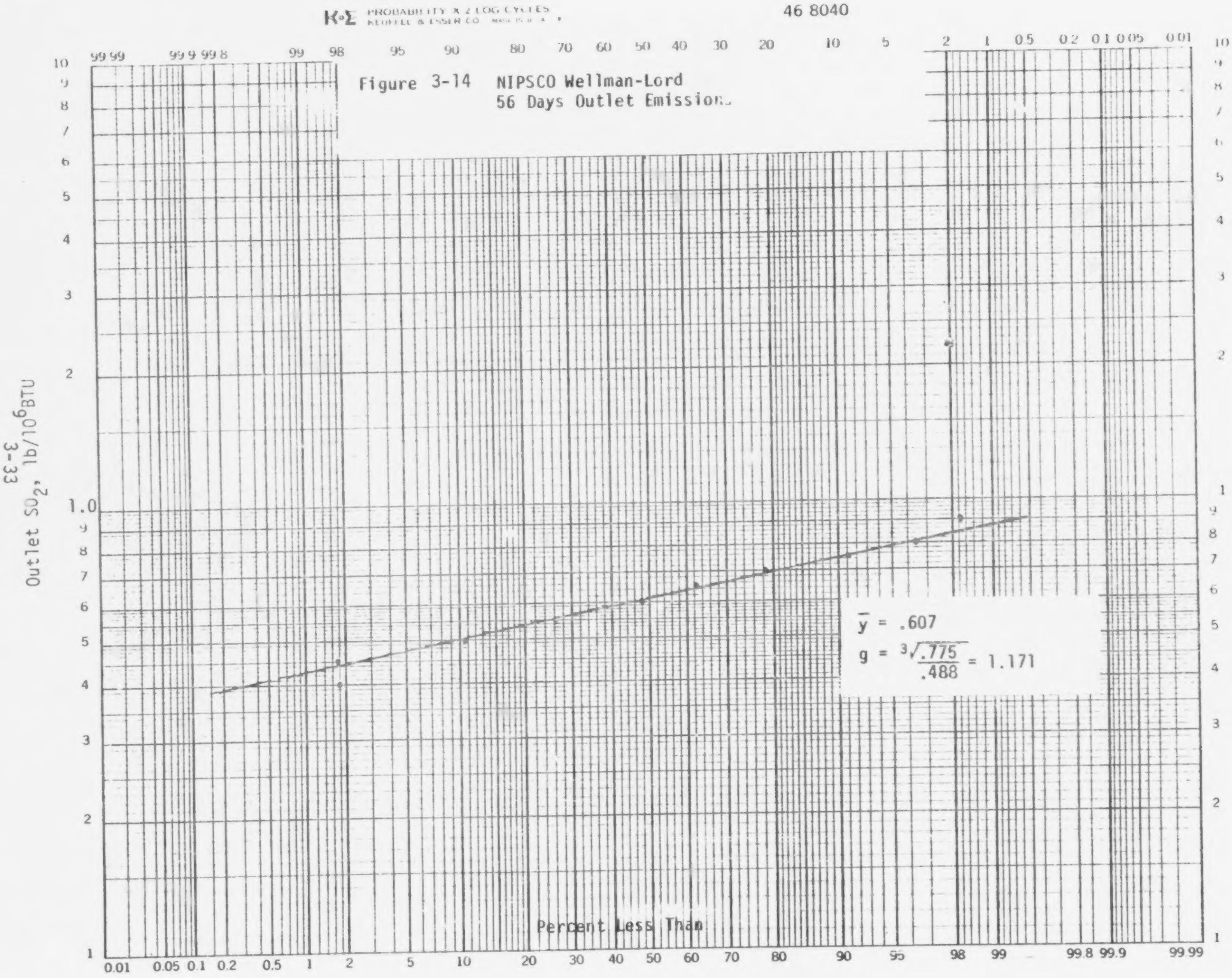


Figure 3-14 NIPSCO Wellman-Lord
56 Days Outlet Emission

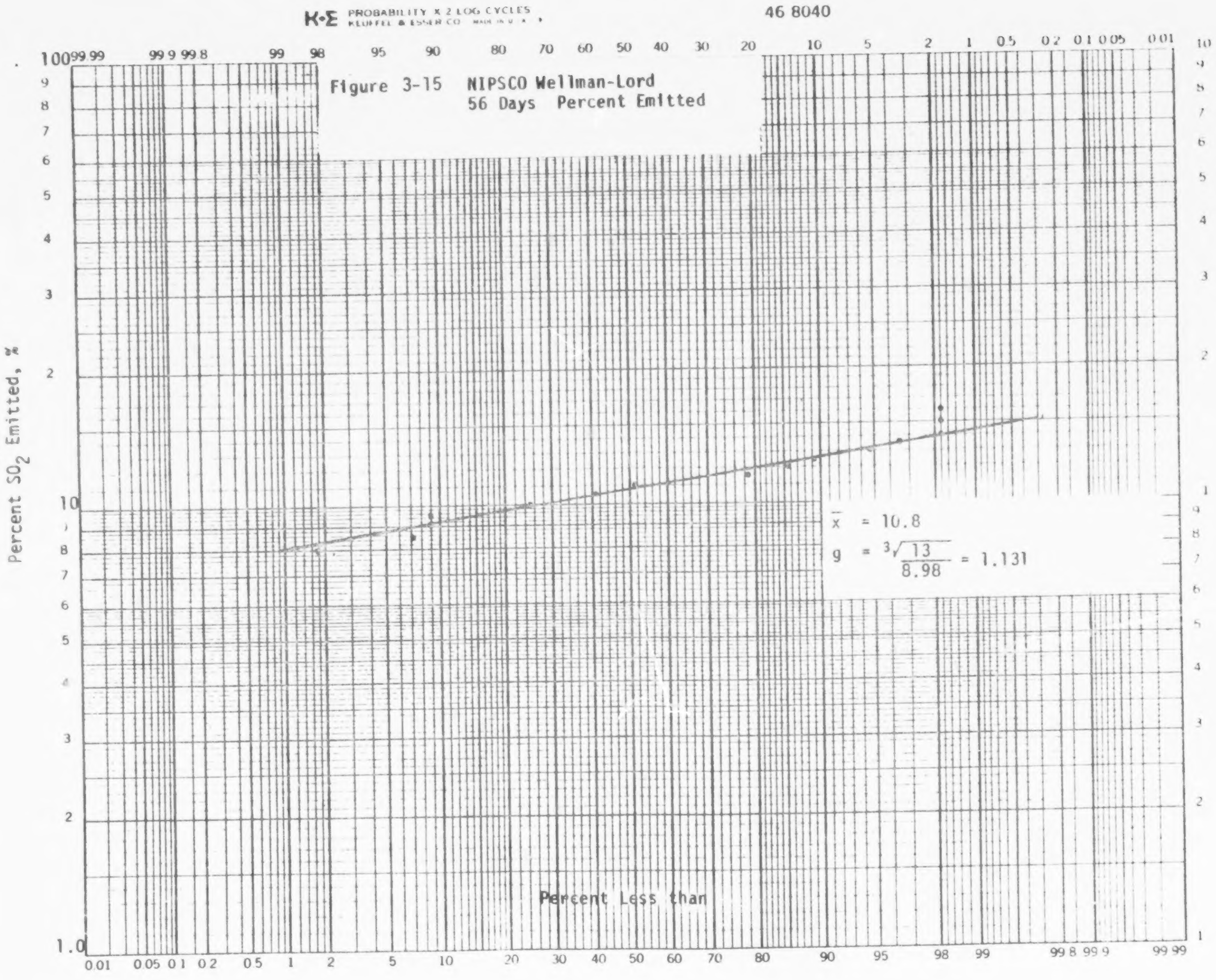


Figure 3-15 NIPSCO Wellman-Lord
56 Days Percent Emitted

with the inlet SO_2 GD of 1.180 showing the effect of averaging coals from two different lots. Outlet SO_2 averaged 0.61 lb/10^6 BTU (1.171 GSD) (Figure 3-14 while percent SO_2 emitted averaged 10.8 percent (89.2 percent recovery) with a GD of 1.131 (Figure 3-3.)

Table 3-2 lists the pertinent statistics from each test program. Comparison of inlet variabilities shows the least variability with the highest sulfur coal. This is perhaps due to the larger amounts of coal used at Conesville per unit time which has the effect of blending when compared to the smaller sources. In the initial report inlet SO_2 GD's varied from 1.05 to 1.12, thus Conesville and Shawnee both fall within this range. The GD of 1.180 at NIPSCO is substantially higher than the 1.12 originally reported for the first 25 day period. As explained earlier, the new GD is misleading because the two periods covered were over a year apart, and two different coal lots are represented.

The outlet emissions and percentage reduction figures are all comparable. Comparison to design figures is not directly possible except at Conesville which has a minimum design SO_2 removal of 89.6 percent (long term). The 89.2 percent average figure reflects the intermittent operation effect upon scrubber performance. The Shawnee TCA system was designed in the late 60's and design data are not available. The Wellman-Lord system at NIPSCO was designed at 90 percent SO_2 removal and 200 ppmv maximum outlet emissions. Conversation with project engineers reveal that the 200 ppmv figure has not been exceeded (this is the number used for control), but that due to lower sulfur coal being used, the 90 percent removal is not being achieved, as is was for the higher sulfur coal used in 1977-1978.

TABLE 3-2

FGD Performance Statistics (24 hour basis)

SO_2 Data

Site/Scrubber Type	No. of Periods	Inlet, lb/10^6BTU (GD)	Outlet, lb/10^6BTU (GD)	Percent emitted (GD)
Conesville TCA/lime	34	7.50 (1.059)	0.80 (1.802)	10.8 (1.801)
Shawnee TCA/lime	42	5.55 (1.116)	0.64 (1.279)	11.4 (1.204)
NIPSCO Wellman-Lord	56	5.70 (1.180)	0.61 (1.171)	10.8 (1.131)

3.2.5 Conclusions

1. All three systems monitored show long term emissions control to levels well below the 1971 NSPS of 1.2 lb SO_2 per million BTU heat input and removal efficiencies approaching 90 percent long term average for high sulfur coals.

2. Variability of one system was a significant problem owing mainly to the interimittent operation of boiler and scrubber in combination. Where continuous operation was achieved at the other sites, variability of scrubber performance was minimized.

3. Monitor availabilities and reliabilities varied from 33.3 to 85.7 on a "total days" basis, which is still not up to capabilities of state of the art monitoring technology.

3.3 PERFORMANCE TEST REPORT B

This test report includes results of monitoring the performance of FGD systems at TVA's Shawnee FGD test facility and at the Lawrence No. 4 steam generator of Kansas Power and Light Company. These tests were performed by EPA with emphasis upon obtaining 30 continuous days of SO_2 data, using monitors certified according to procedures in the October 6, 1975, *Federal Register*.

At the Shawnee site, a venturi scrubber using limestone with adipic acid additive was monitored for 49 continuous days with the existing on-site SO_2 monitoring system. Due to some monitoring problems, 31 days of data were obtained (63 percent reliability) which showed average SO_2 emissions of 0.22 $lb/10^6$ Btu and SO_2 emission reduction of 96.1 percent.

EPA used a mobile sampling van to obtain SO_2 data from the Lawrence No. 4 FGD unit, a venturi scrubber with limestone applied to combustion of low-sulfur coal. For the 22 days of continuous scrubber operation (with two periods of interruption due to sampling pump failures), the SO_2 monitors were 86 percent reliable, measuring average SO_2 emissions of 0.03 $lb/10^6$ Btu and 96.6 percent SO_2 removal for 22 days. The relative variability in outlet emissions from both sources were significantly higher than for previous tests, due to the low absolute values of the data.

All instrumentation and procedures followed have been previously discussed in section 3.2. A noteworthy exception is the mobile van equipped with fluorescence analyzers for sulfur dioxide and polarographic/paramegnetic analyzers for oxygen at the Lawrence test site.

At both installations, SO_2 and O_2 concentrations were measured upstream and downstream of the FGD system using continuous instrumental monitors. Copies of boiler operation logs and FGD system operation logs were obtained to document process operating conditions during the monitoring periods.

As in all cases, the instruments used to generate data have been subjected to the appropriate test procedures (Federal Register, Vol. 40:194, October 6, 1975) to assure accuracy of all data reported herein.

3.3.1 Description of Test Sites

3.3.1.1 Shawnee FGD Prototypes, Tennessee Valley Authority

The Shawnee Power Station, operated by the Tennessee Valley Authority (TVA), is a coal-fired steam generation station having 10 turbines, each served by a boiler and stack. A portion of the exhaust gases from one of these stacks is directed for use with three pilot plant scale wet scrubbers systems - a venturi with a spray tower after absorber, a turbulent contact absorber (TCA), and a marble bed absorber. Testing was performed on the venturi/spray tower using limestone enhanced with adipic acid and the TCA using lime only. This report describes the test and results for the venturi/spray adipic acid enhanced limestone system.

The venturi system was manufactured by Chemical Construction Company in the late 1960's and contains an adjustable throat which permits control and variation of pressure drop. No design performance data are available.

Figure 3-16 is the process flow diagram for the Shawnee venturi system. For this test, limestone and adipic acid were added to the scrubber effluent hold tank with adipic acid concentrations maintained at 1500 parts per million volume during the entire test period.

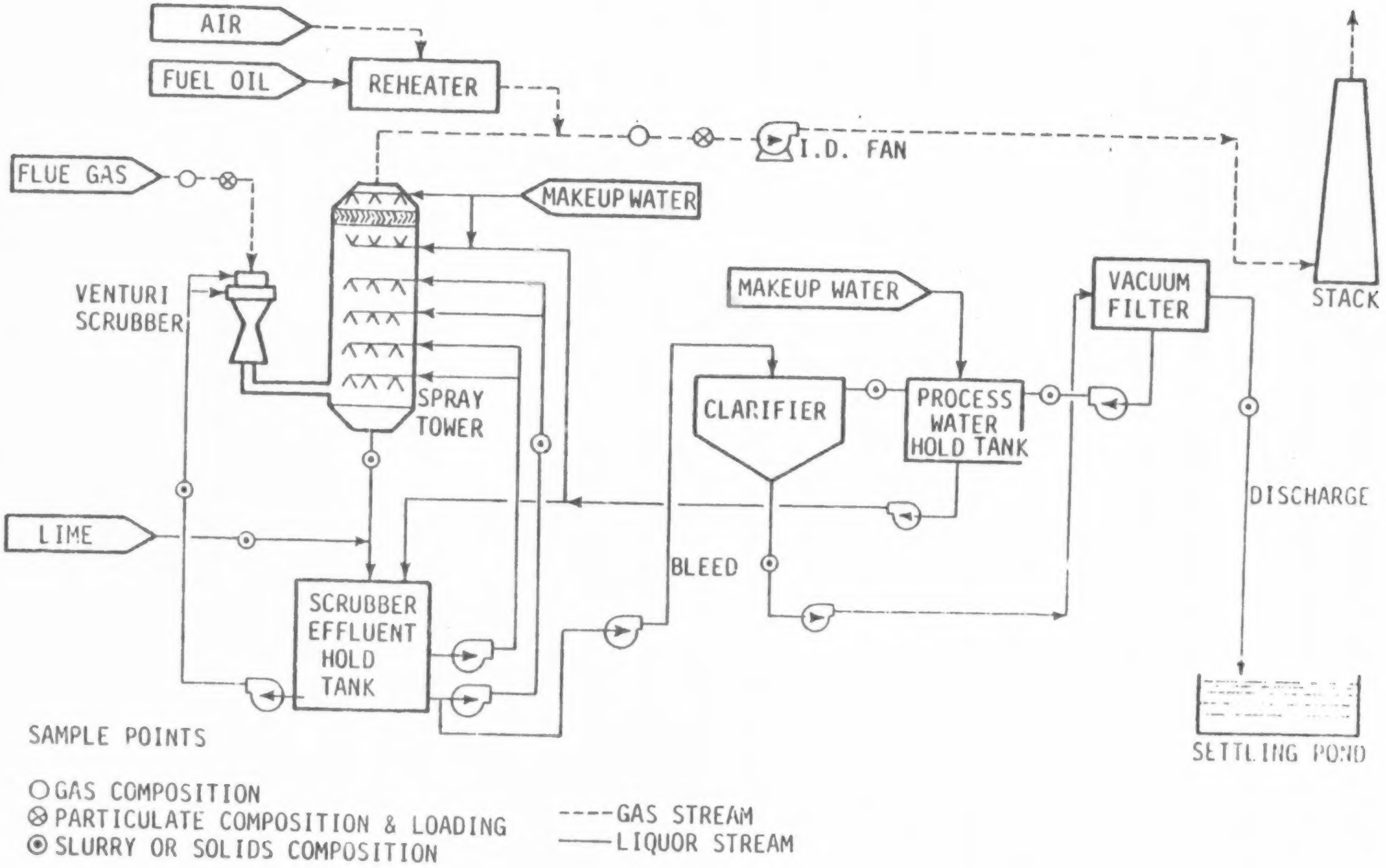

AIR
FUEL OIL
REHEATER
I.D. FAN
STACK
FLUE GAS
MAKEUP WATER
VENTURI SCRUBBER
SPRAY TOWER
MAKEUP WATER
VACUUM FILTER
CLARIFIER
PROCESS WATER HOLD TANK
DISCHARGE
LIME
BLEED
SCRUBBER EFFLUENT HOLD TANK
SETTLING POND
SAMPLE POINTS
○ GAS COMPOSITION
⊗ PARTICULATE COMPOSITION & LOADING
⊙ SLURRY OR SOLIDS COMPOSITION
----GAS STREAM
——LIQUOR STREAM

Figure 3-16

Tennessee Valley Authority, Shawnee No. 10 Prototype Unit: General Process Diagram.

3.3.1.2 Lawrence Unit No. 4, Kansas Power and Light Company

The Lawrence No. 4 steam generating unit is rated at 125 megawatt electrical output and burns low-sulfur Wyoming coal with an average heating value of 10,000 Btu/hr, sulfur content of 0.5 percent and ash content of 9.8 percent. The FGD system consists of two 50 percent capacity scrubber modules of a Combustion Engineering - Bed Scrubber/Spray Tower two-stage system as shown in Figure 3-17. Pulverized limestone slurry contacts the flue gas in both the rod scrubbers and spray tower. Overall SO_2 removal is designed for a minumum 73 percent. A detailed description of this system may be found in EPA 600/7-78-058b pp. 255-276, "Proceedings of the Symposium on Flue Gas Desulfurization, November 1977.

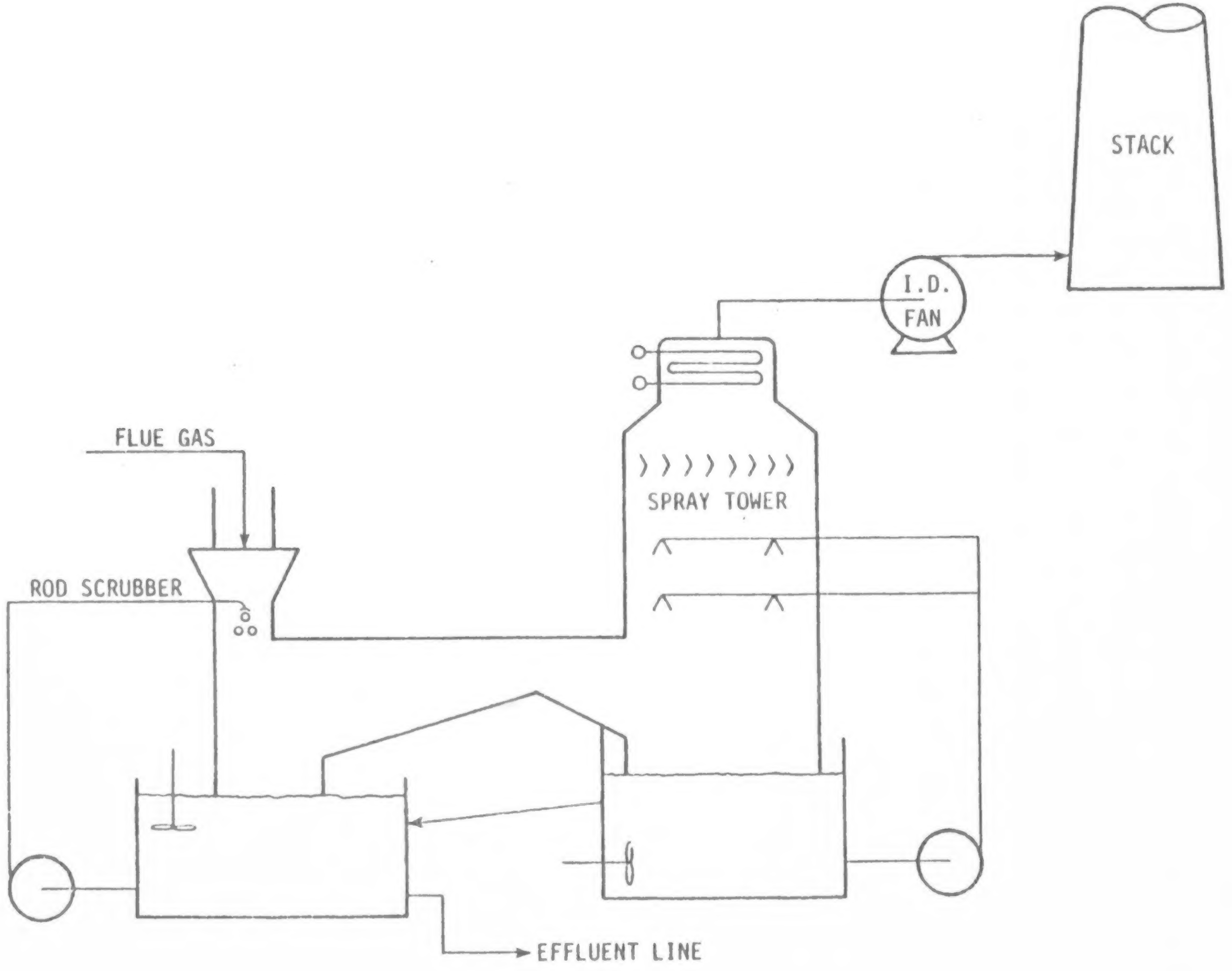

STACK
I.D. FAN
FLUE GAS
SPRAY TOWER
ROD SCRUBBER
EFFLUENT LINE

Figure 3-17 Kansas Power and Light, Lawrence No. 4 Operational FGD System: Simplified Flow Diagram.

3.3.2 Data Gathering Systems

3.3.2.1 Shawnee FGD Prototypes, Tennessee Valley Authority

A schematic diagram of the monitoring system used at each monitoring location at Shawnee is shown in Figure 3-6. The sulfur dioxide (SO_2) instrument at each location is a DuPont 460 analyzer.[1] The oxygen (O_2) analyzer is a Thermox model WDG 3 instrument. The ranges of the scrubber inlet SO_2 analyzers are set at 0-4000 ppm SO_2 and the ranges of the two scrubber outlet SO_2 analyzers are 0-1000 ppm. The ranges of O_2 analyzer are all set at 0-10 percent O_2. The SO_2 and O_2 probes tips are located at the stack centers with the O_2 rpobe approximately one stack diameter upstream of the SO_2 probe at each location. The analyzers operating on approximately 8-minute cycles during which stack gas concentration measurements are made continuously except for an automatic 1-minute backflush period. Concentration measurements are recorded continuously on four strip chart recorders located in the scrubber control room.

The moisture content correction for the SO_2 gas measurements was determined from the temperature measurement in the sample gas stream immediately following the knock-out trap in the analyzer case. This gas was assumed saturated at this temperature. The moisture content correction for the O_2 gas measurements was the stack moisture content as the O_2 analyzers measured a wet gas stream.

---

[1] Mention of a specific company or product name does not constitute endorsement by the Environmental Protection Agency.

3.3.2.2 Lawrence Unit No. 4, Kansas Power and Light Company

The monitoring system used at Lawrence No. 4 consisted of an extraction/ conditioning module and a mobile laboratory which housed the analyzers. Thermo Electron Model 40 pulsed fluorescence analyzers were utilized to monitor sulfur dioxide at both the inlet and outlet of the south scrubber. A Beckman Model 742 polarographic analyzer was used to monitor the inlet oxygen concentration while a MSA paramagnetic analyzer was utilized to monitor outlet concentration of oxygen.

Figure 3-18 contains a schematic diagram of the sample extraction/ conditioning module. Briefly, the system consists of a heated probe with a 3/4 inch nozzle oriented away from the gas flow, a heated filter box/pump box assembly, a refrigeration cooler and finally a distribution panel to readily enable the sampling of calibration or sample streams. All connecting lines from the probe to the refrigeration cooler consisted of 1/2 inch O.D. Teflon tubing was used. A 0-15 psi back pressure regulator was placed at the end of the exhaust vent line to cause a fraction of the gas from the source to be transported through the analyzers.

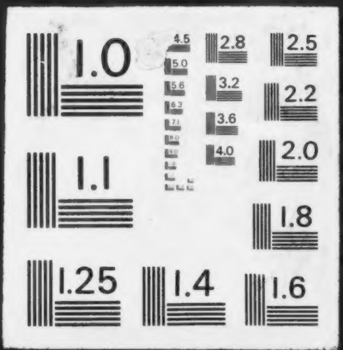
Data acquisition was accomplished using an Accurex Auto Data Nine data acquisition system with a 24-channel Esterline Angus multipoint recorder as a backup in case of Auto Data Nine failure.

The extraction system was operated at a constant flow rate of approximately 1.5 ft^3/min with a constant back pressure of 5 psi. All heat traced lines and heated boxes were operated at temperatures ranging from 130°C to 200°C. Sample flows to the oxygen analyzers were maintained at 1.6 ft^3/hr while

4 OF 4

PB

298510



1.0
4.5
5.0
5.6
6.3
7.1
2.8
3.2
3.6
4.0
2.5
2.2
2.0
1.1
1.8
1.25
1.4
1.6

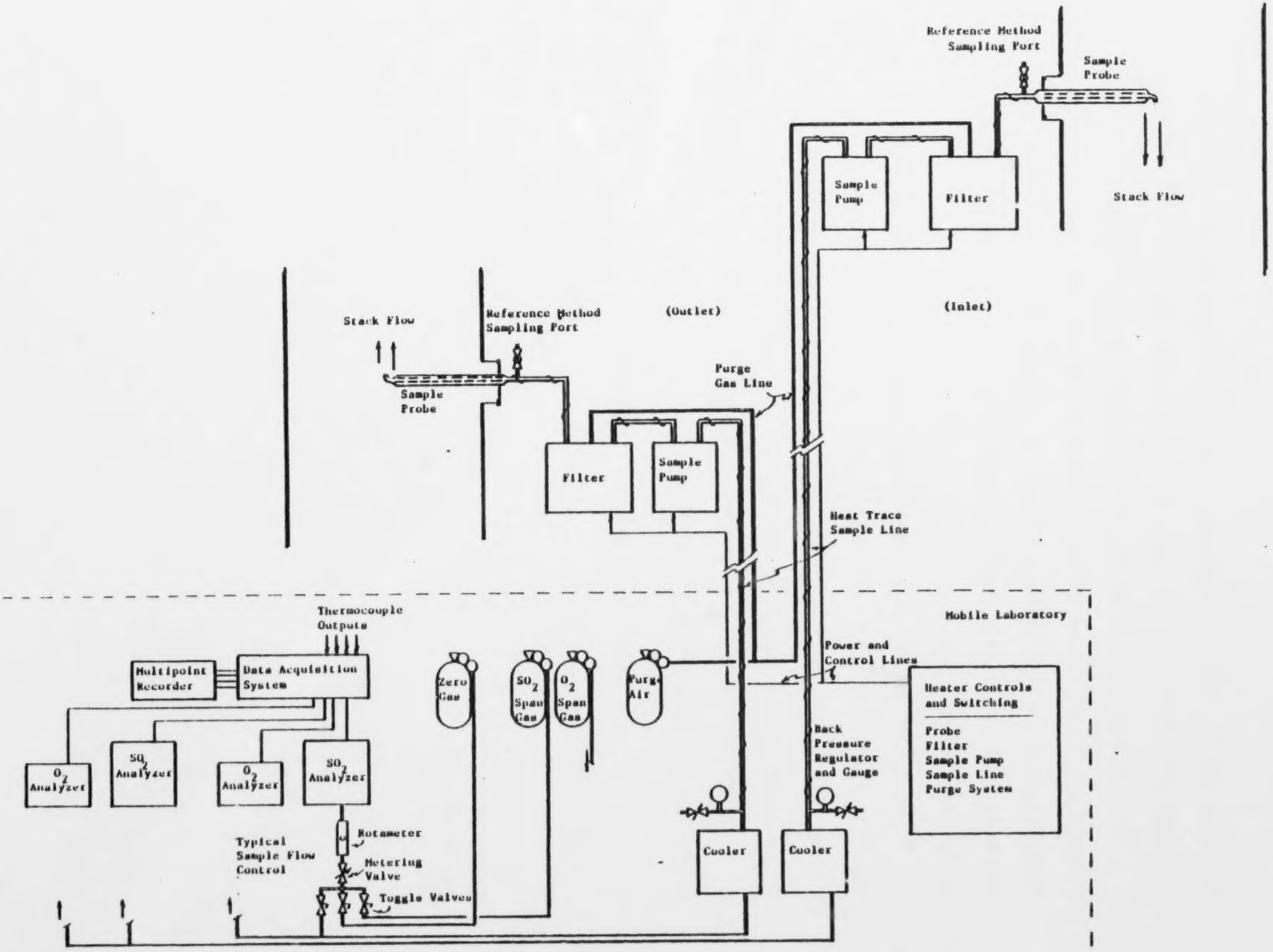

Reference Method
Sampling Port
Sample
Probe
Stack Flow
Sample
Pump
Filter
(Inlet)
Stack Flow
Reference Method
Sampling Port
Sample
Probe
(Outlet)
Purge
Gas Line
Filter
Sample
Pump
Heat Trace
Sample Line
Mobile Laboratory
Thermocouple
Outputs
Multipoint
Recorder
Data Acquisition
System
Zero
Gas
SO_2
Span
Gas
O_2
Span
Gas
Purge
Air
Power and
Control Lines
Heater Controls
and Switching
Probe
Filter
Sample Pump
Sample Line
Purge System
Back
Pressure
Regulator
and Gauge
O_2
Analyzer
SO_2
Analyzer
O_2
Analyzer
SO_2
Analyzer
Rotameter
Typical
Sample Flow
Control
Metering
Valve
Toggle Valves
Cooler
Cooler

Figure 3-18 Schematic of Monitoring System of Lawrence No. 4

those for the SO_2 analyzers were not visually maintained as the analyzers contained individual sampling pumps which controlled the analyzer sample demand.

All analyzers were calibrated daily at approximately 0900 with a zero, midscale and 90 percent of full-scale range standards. Data was collected instantaneously at five minute intervals by the Auto Data Nine. These data printouts also contained secondary parameters such as line temperatures, cooler temperatures, etc.

Prior to the initiation of monitoring, a profile was conducted at both the inlet and outlet to the scrubber in order to ensure a homogeneous gas stream. At the completion of this exercise, the probes were oriented as close to the center of the duct as possible.

The invidivual analyzers were operated on the ranges shown in Table 3-3 and calibrated with the type of standard listed.

TABLE 3-3. ANALYZER SPECIFICATIONS

Analyzer	Location	Range	Calibration Standard
TECO Model 40	Inlet	0-1000 ppm	SO_2/air
TECO Model 40	Outlet	0-100 ppm	SO_2/air
Beckman Model 742	Inlet	0-10%	O_2/N_2
MSA Paramagnetic Analyzer	Outlet	0-10%	O_2/N_2

3.3.3 Data Reduction Procedures

The types of data that were collected for reduction purposes were:

inlet SO_2 strip chart (2 inlets)
inlet O_2 strip chart (2 inlets)
outlet SO_2 strip chart (2 outlets)
outlet O_2 strip chart (2 outlets)

scrubber logs (including boiler load and coal feed rate)

instrument logs

instrument calibration data sheets

manual test results

The data were first logged in as received and then were reviewed for possible data gaps. The charts were then transcribed to a tabular format using a strip chart data digitizer. The tabular data were then processed through a manual keypunch operation so that appropriate scale factors, moisture values, process data, and descriptive comments could be included prior to data listing. The punched cards were then processed by computer to obtain a data listing and calculated results for each 15 minute data point. The data listings were reviewed by the EPA contractor for keypunch or other transcription errors. The scrubber and instrument logs were reviewed so that periods of boiler outage, scrubber outage, bypass, startup or shutdown could be properly identified and coded so that these data would not be included in the calculation of averages and summaries.

After data editing was completed, average summaries were prepared. Averages based on the 15-minute data were prepared for consecutive 1-hour, 3-hour, 8-hour, and 24-hour intervals. In order to calculate an average result for a single interval, it was specified that at least 75 percent of the 15-minute data points be available for that interval. For example, an 8-hour average could only be calculated when 24 of the possible 32 15-minute data points were available. When less than 75 percent of the data were available for an interval, an average was not calculated and blanks were entered in the summary printouts.

After each 30 days of average interval data, a statistical summary was prepared to determine the following parameters for the average.

mean

average deviation

minimum

percent standard deviation

standard deviation

maximum

range

These parameters were calculated assuming the data were normally distributed.

The calculation procedures used to convert the analyzer outputs for sulfur dioxide and oxygen concentrations to mass emission factors are given in 40 CFR 60 Subpart D. This procedure is known as the F-factor approach and is outlined below:

$$E = \frac{CFK}{1-M} \times \frac{20.9}{20.9-\frac{O_2}{1-M}}$$

Where E = Emission factor - lb/million Btu

C = SO_2 concentration - ppmv, wet basis

F = Stoichiometric conversion factor, 9820 dscf/million Btu for subbituminous coal

K = Conversion factor, 1.659×10^{-7} lb/dscf per ppmv

O_2 = Oxygen concentration, percent by volume as measured

M = Moisture fraction as measured (for dried samples, M=0)

The sulfur dioxide and oxygen concentration results were obtained by multiplying the strip chart readings as a percent of scale by the appropriate calibration factor.

The emission factor was calculated for each FGD system inlet and outlet test point. The sulfur dioxide removal efficiency for a module is calculated by:

$$\text{Efficiency} = \frac{\text{Ein} - \text{E out}}{\text{Ein}} \times 100 \text{ percent}$$

When more than one inlet and/or outlet test point was monitored, the total system emission factors and sulfur dioxide removal efficiencies were calculated by a weighted average procedure. The equation for this calculation for total system efficiency is given by:

$$\text{EFF total} = \text{EFF}_A\ (F_A) \pm\ \text{EFF}_B(F_B)$$

Where,

$\text{EFF}_{\text{total}}$ = total system efficiency

EFF_A = efficiency of module or module set A

F_A = fraction of gas flow through module or module set A

EFF_B = efficiency of module or module set B

F_B = fraction of gas flow through module or module set B

3.3.4 Data Analysis

3.3.4.1 Data Calculation Assumptions

In previous SO_2 monitoring reports, several assumptions were made due to direct oxygen or moisture readings being unavailable, which led to a maximum error level due to the assumptions of 3 percent in emissions and 0.5 percent in percent removal efficiency.

For the data to be described, no assumptions were made.

3.3.4.2 Data Availability

Table 3-4 shows the data gathering breakdown for the two sites. The total days sampling time was ascertained, then the boiler and scrubber down time was subtracted to yield the net days availabile for scrubber performance data. Data for each one-hour period was compiled and 24-hour periods characterized as full data periods, i.e., when the boiler/scrubber system was operable 18 hours or more and 18 hours or more of monitor data was obtained within a calendar day.

As shown in Table 3-4 the percentage data availability ranged from 63.3 percent total days at Shawnee to 84.6 percent at Lawrence No. 4 for overall efficiency, where both inlet and outlet data were available.

Comparison of performance at the Shawnee site to design is not possible since the design SO_2 removal for adipic acid injection is not known due to the limited operating experience. What is significant is that the limestone/adipic acid venturi system achieved 96.1 percent SO_2 removal on identical flue gas to that which the lime-TCA FGD system previously reported an 88.6 percent SO_2 removal.

TABLE 3-4 CATEGORIZATION OF DATA

	Shawnee Venturi FGD	Lawrence FGD
Total Days	49	37
Boiler Down	0	0
Scrubber Down	0	11
Net	49	26
Full Data Days	31	22
% Data Available	63.3	84.6

Comparison of the Lawrence performance to design SO_2 removal is interesting in that the 73 percent design figure was easily exceeded by the 96.6 percent figure demonstrated during the 22 days testing. This is because a slight overdesign of a low sulfur FGD system may show significant additional SO_2 removal when compared to similar overdesign of a high sulfur FGD application. Another way of stating this is that removal of an extra 50 ppm is very significant when there is only 60 ppm remaining, as compared to when 600 ppm remain. This ease of scrubbing low sulfur coals was discussed in EPA 600/7-78-030 b, March 1978, by Bechtel Corporation.

3.3.4.3 Statistical Analyses

Figures 3-19, 3-20, and 3-21 graphically illustrate FGD performance at the Shawnee venturi site using limestone with adipic acid additive. Figure 3-19 shows inlet SO_2 loadings average 5.6 percent $lb/10^6$ Btu with a geometric dispersion (GD) of 1.070. Figure 3-20 shows outlet SO_2 emissions averaging 0.22 $lb/10^6$ Btu with a GD of 1.518. Percent SO_2 emitted averaged 3.9 percent (96.1 percent SO_2 removal) for the 31 day period with a GD of 1.427.

Figures 3-22 through 3-24 show the performance of the Lawrence venturi-spray FGD using limestone slurry. Figure 3-22 shows average inlet SO_2 loadings of 1.02 $lb/10^6$ Btu, while Figure 3-23 shows average outlet SO_2 emissions of 0.03 $lb/10^6$ Btu. Geometric dispersions are 1.122 and 2.342 for inlet and outlet respectively. In Figure 3-24 the percent SO_2 emitted is shown to be 3.4 (96.6 percent SO_2 removal) with a GD of 1.885.

The high geometric dispersions occur for both systems on the outlet and percent emissions due to the extrememly low emission levels; the magnitude of variance [e.g., $\bar{x}$ (g-1) and $\bar{x}$/(g-1)] is smaller than for previous results from FGD monitoring studies.

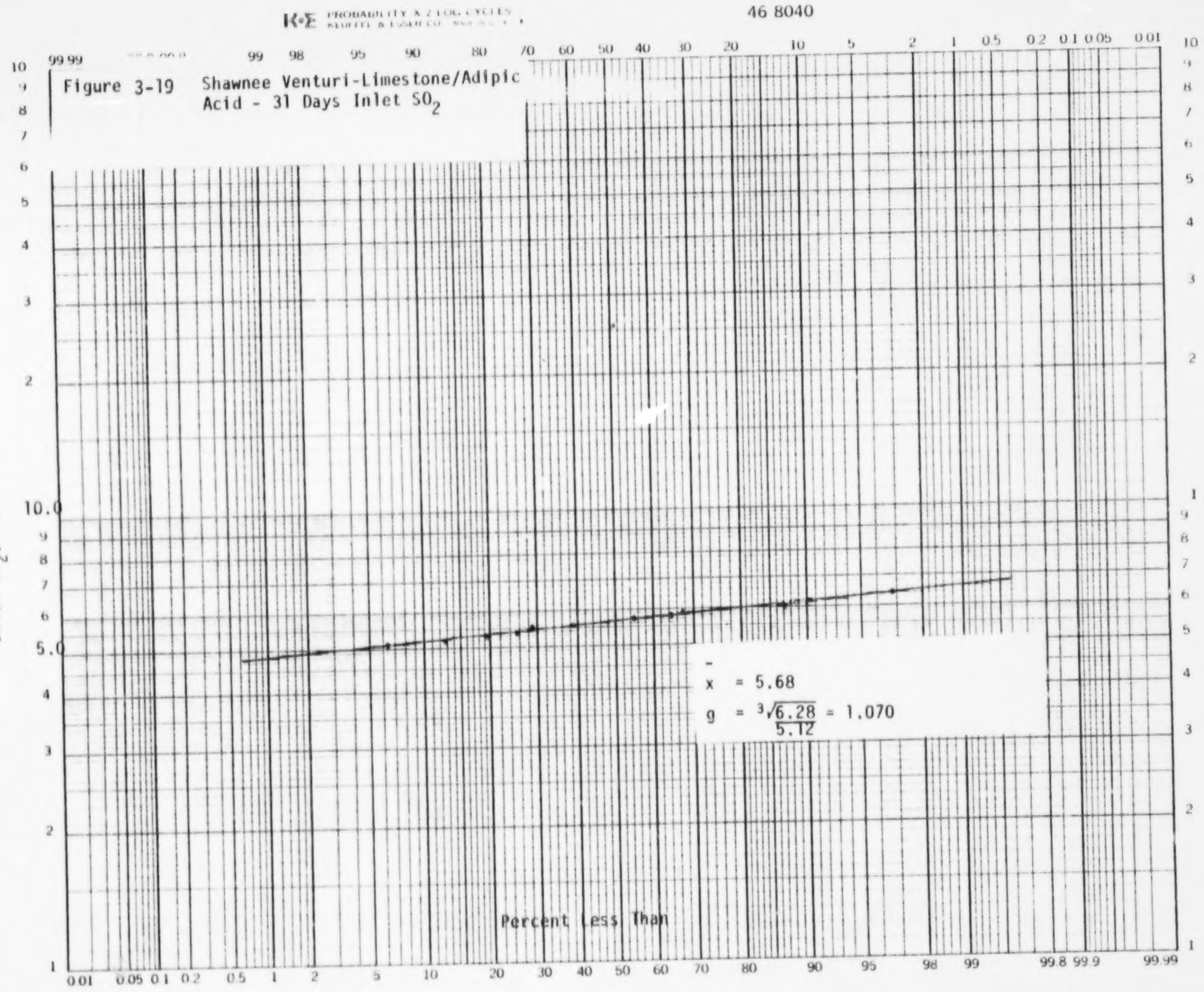
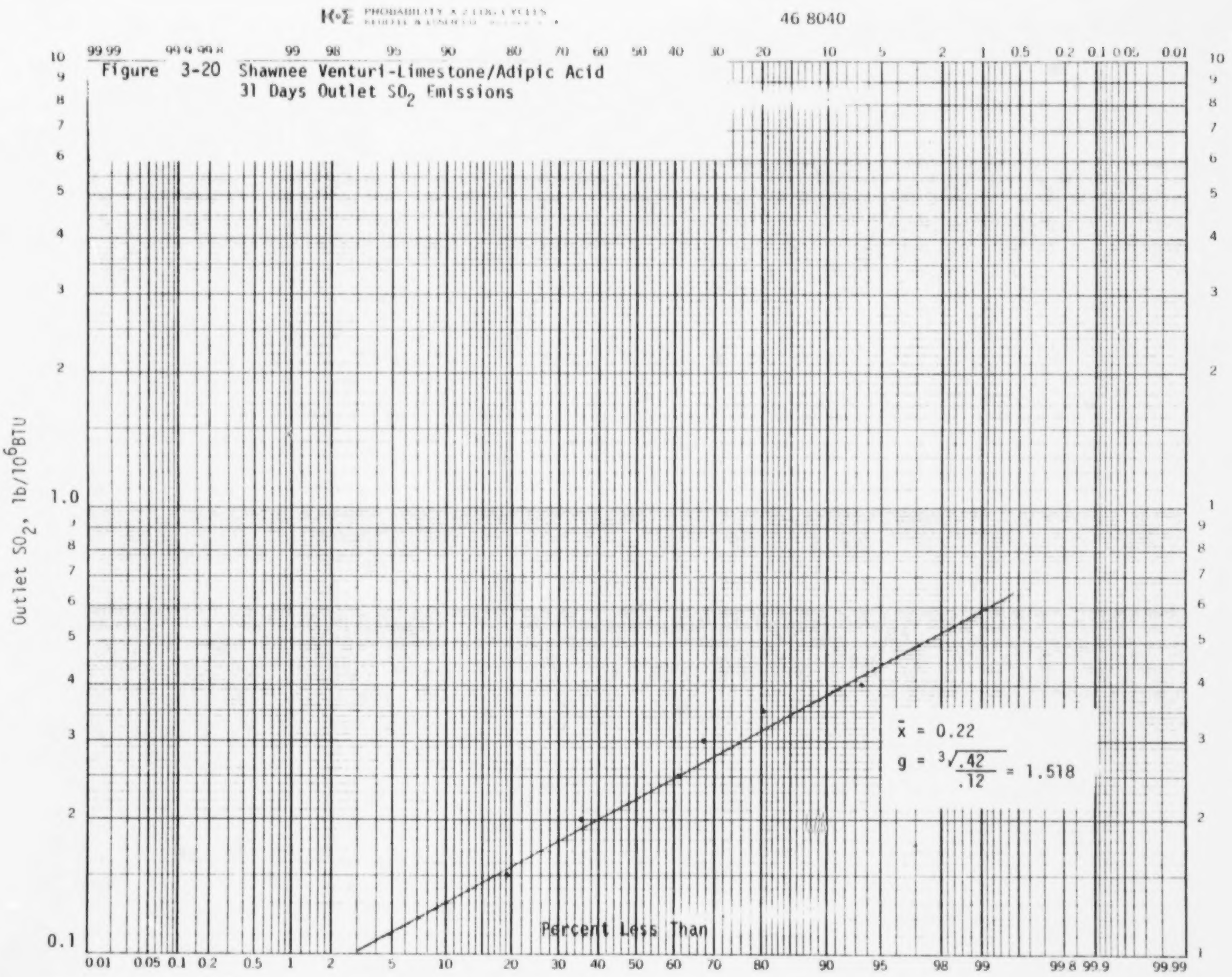


Figure 3-19 Shawnee Venturi-Limestone/Adipic Acid - 31 Days Inlet SO_2

$\bar{x} = 5.68$

$g = \sqrt[3]{\frac{6.28}{5.12}} = 1.070$

Figure 3-20 Shawnee Venturi-Limestone/Adipic Acid
31 Days Outlet SO_2 Emissions



$$\bar{x} = 0.22$$

$$g = \sqrt[3]{\frac{.42}{.12}} = 1.518$$

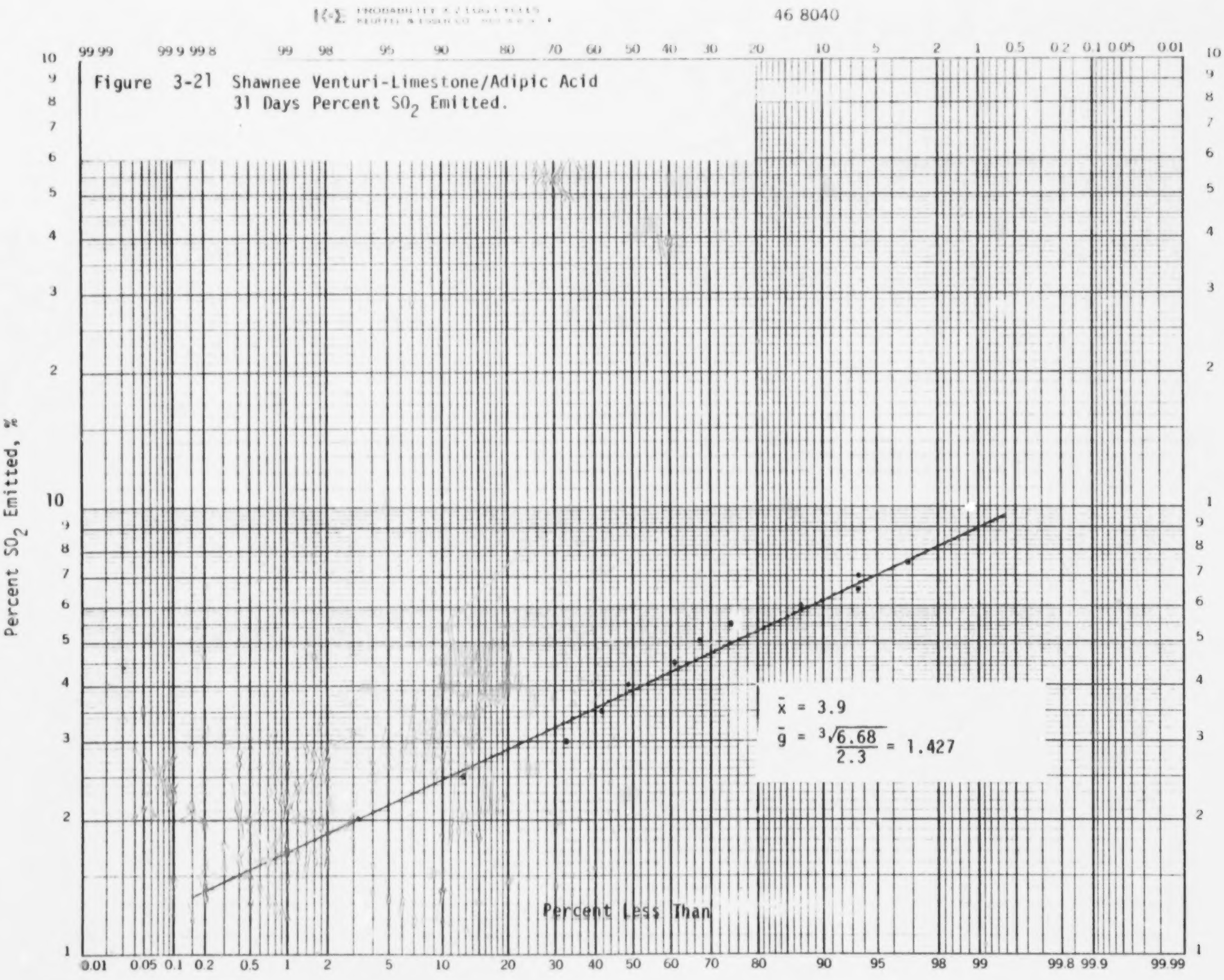


Figure 3-21 Shawnee Venturi-Limestone/Adipic Acid 31 Days Percent SO_2 Emitted.

$\bar{x} = 3.9$

$\bar{g} = \sqrt[3]{\frac{6.68}{2.3}} = 1.427$

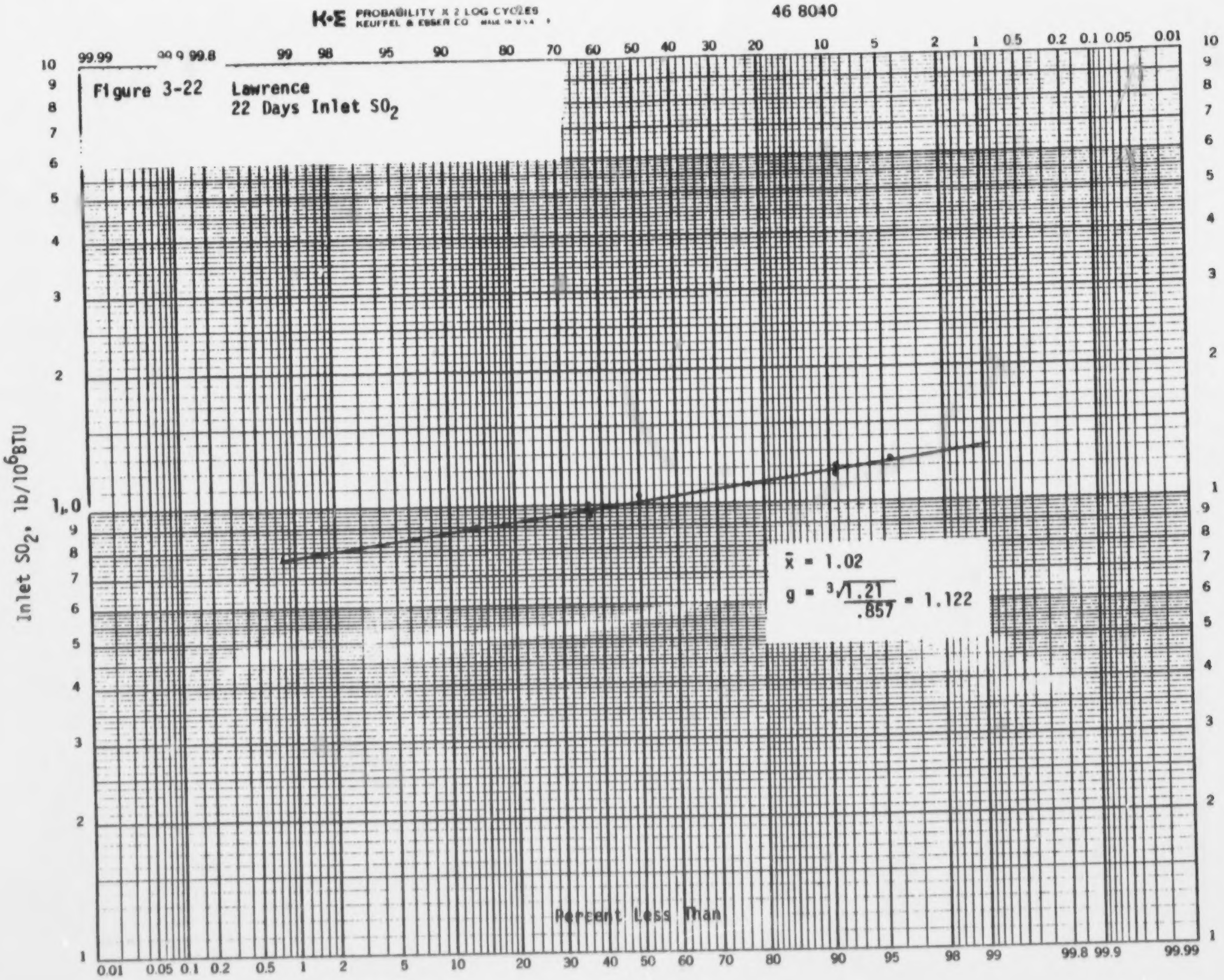


Figure 3-22 Lawrence
22 Days Inlet SO_2

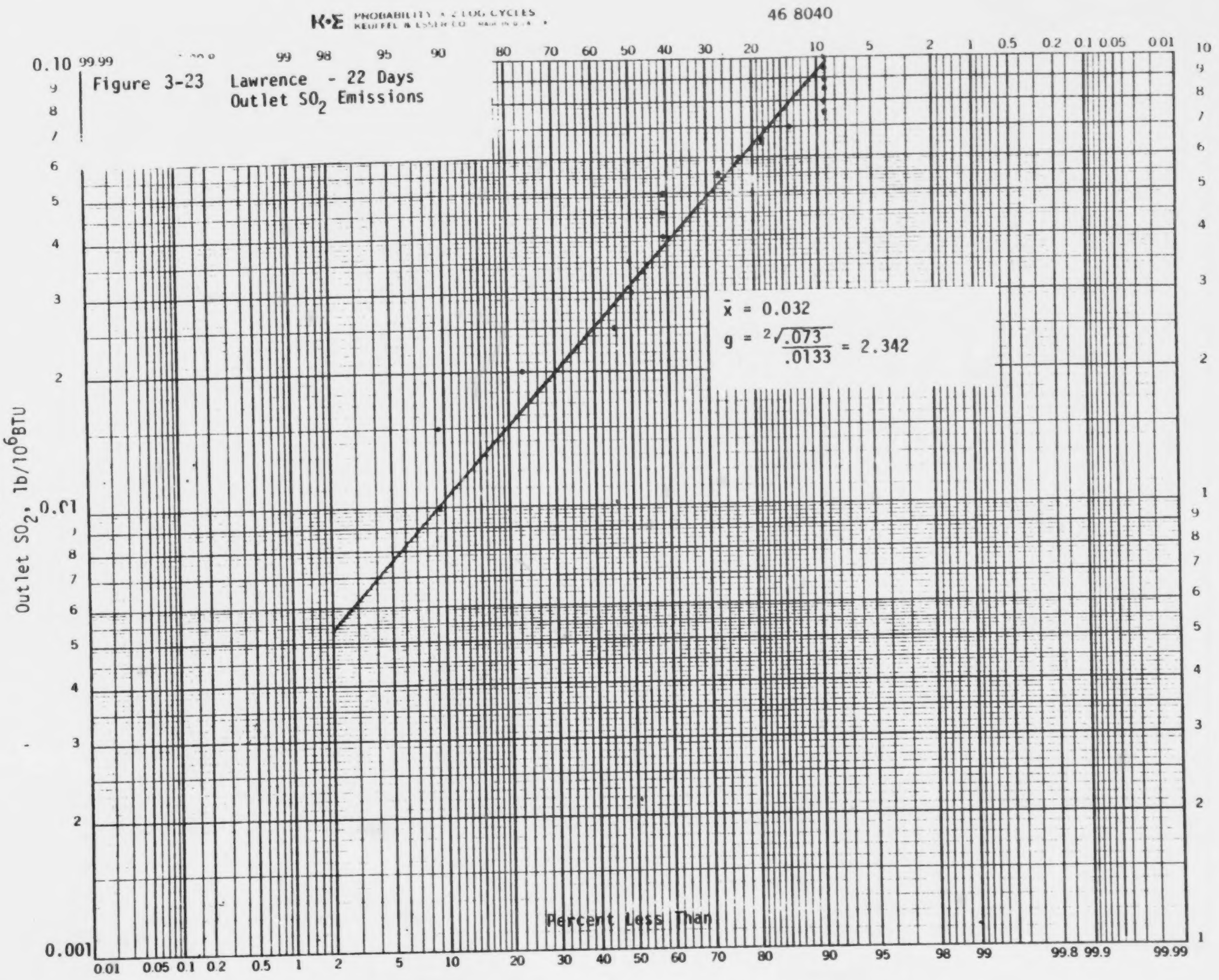


Figure 3-23 Lawrence - 22 Days Outlet SO_2 Emissions

$\bar{x} = 0.032$

$g = \sqrt[2]{\frac{.073}{.0133}} = 2.342$

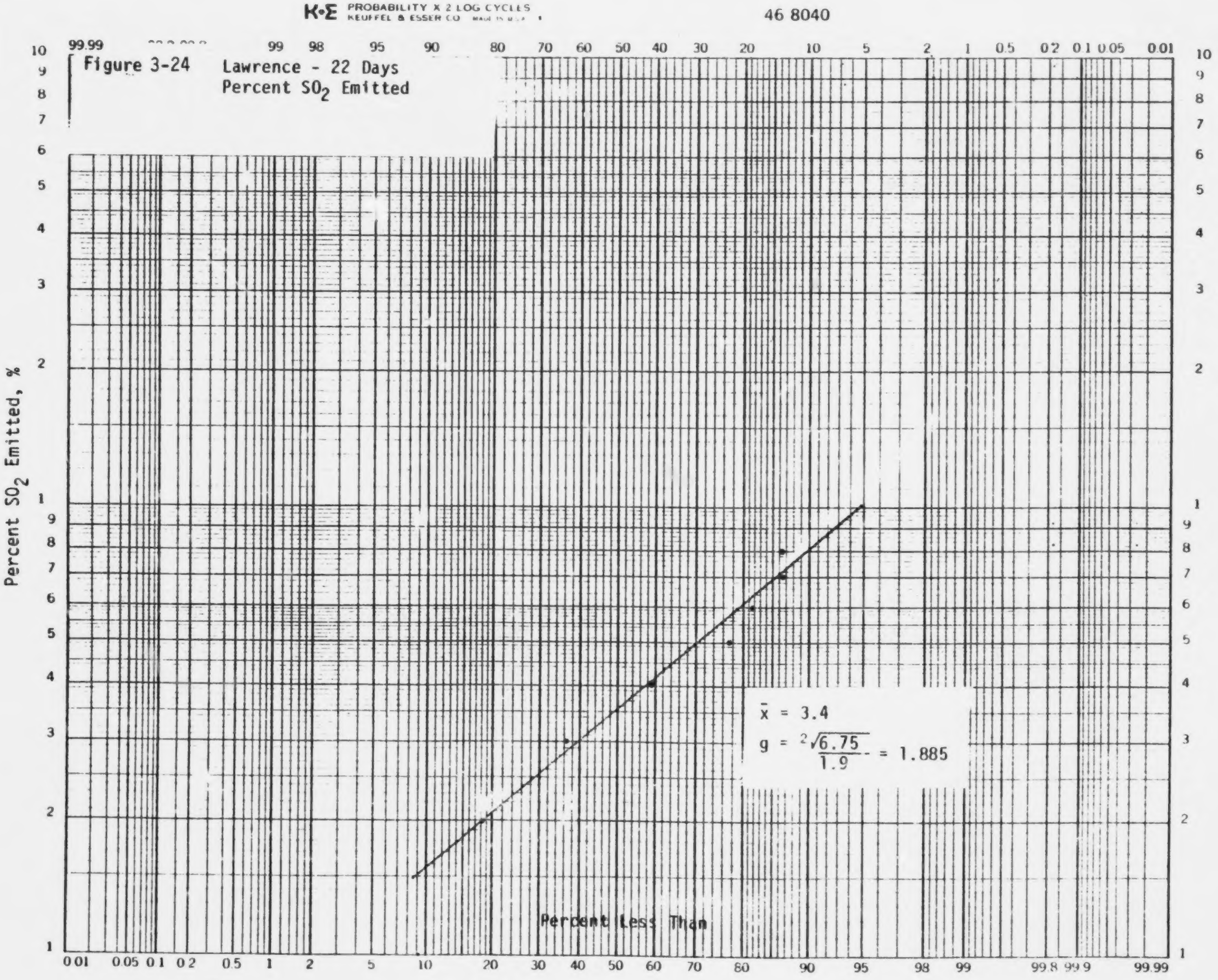


Figure 3-24 Lawrence - 22 Days Percent SO_2 Emitted

3.3.5 Conclusions

1. The two systems monitored in this report illustrate very low emissions achievable with FGD systems on low sulfur coal with conventional limestone scrubbing and on high sulfur coal with conventional limestone scrubbing assisted by low concentrations (1500 ppm) of adipic acid.

2. The relative ease of SO_2 removal from low sulfur coal flue gas is shown by the Lawrence data, where 96.6 percent SO_2 is removed.

3. The benefits of adipic acid injection are shown by comparison of the system examined here compared to conventional lime scrubbing, where adipic acid enhancement of limestone showed 96.1 percent SO_2 removal compared to 88.6 percent measured on a parallel system with lime scrubbing only.

3.4 DRY SO_2 CONTROL

3.4.1 Introduction

Although a number of flue gas desulfurization processes which are based upon lime/limestone wet scrubbing are commercially available, the electric utility industry and flue gas desulfurization equipment vendors have continued to develop alternative control technologies. One of the major developments during the past two years is a dry SO_2 control technology based upon spray dryers.

A simplified flow sheet for a typical spray dryer is shown in Figure 3-26. The hot flue gas (280 - 350° F) enters the spray dryer contactor in which a slurry or concentrated sorbent solution contacts the flue gas. The water which is associated with the slurry or solution is evaporated by the hot flue gas while simultaneously, the sulfur oxide reacts with the alkaline reagent (either Na_2CO_3, CaO, $NaHCO_3$ or $Ca(OH)_2$), and hence, the term spray dryer. The flue gas which contains dried reagent, fly ash, and reaction products leaves the spray dryer contactor, and the particulate matter is collected with an electrostatic precipitator (ESP) or a baghouse. Baghouses have a slight advantage over ESP's by allowing additional contact between the flue gas and any unreacted sorbent leaving the spray dryer. Since the flue gas leaving the spray dryer is "hot" (150 - 180° F), no reheat is required.

Antelope Valley Station Flow Diagram

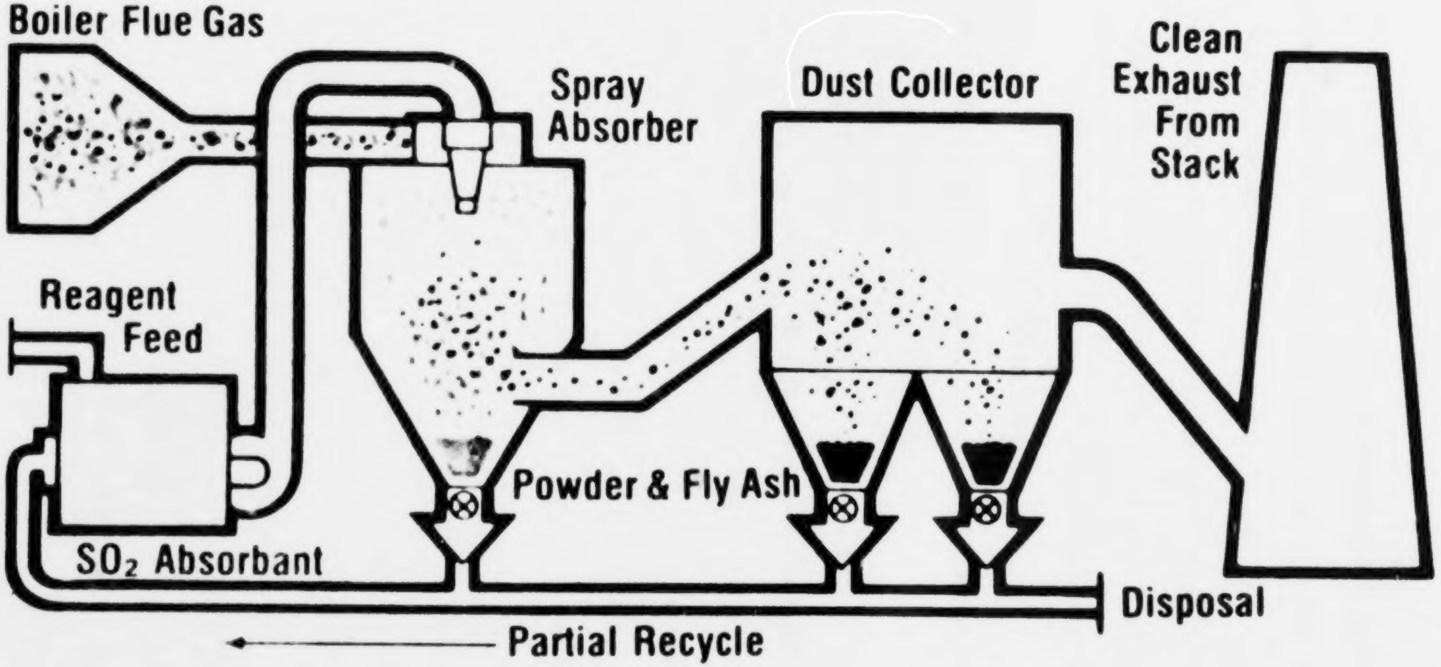

Boiler Flue Gas
Spray Absorber
Dust Collector
Clean Exhaust From Stack
Reagent Feed
Powder & Fly Ash
SO_2 Absorbant
Disposal
Partial Recycle

Figure 3-26

3.4.2 Pilot Scale Testing

Four pilot plants have been operated to develop design data and to estimate the dry SO_2 control system's operating and capital costs. Four vendors have participated in the pilot scale test program which is listed in Table 3-5. All of the pilot plants were operated under the following conditions:[3]

inlet gas temperature	310° F
inlet SO_2 concentration	400 - 2000 ppm
coal	North Dakota lignite and Powder River Basin sub-bituminous coals

Both of the fuels used are highly alkaline. A typical analysis for the Powder River coal is given in Table 3-6. The fly ash contains an average 20+ percent of lime; much of which is available for reaction with the sulfur oxide. The effect of the fly ash alkalinity, which is a source of lime, is to lower the apparent lime stoichiometric ratio which is required to achieve a specified SO_2 percent reduction. For example, it has been reported[2] that contacting water with the fly ash laden flue gas in the spray dryer can reduce SO_2 emissions by as much as 60 percent. Based upon the pilot plant testing completed to date, a relationship between percent reduction and stoichiometic ratio for lime is given in Figure 3-27 for an alkaline fly ash. If a coal which was not alkaline were used, the stoichiometric ratio would increase dramatically, by as much as a factor of two based upon proprietary data.

TABLE 3-5

SPRAY DRYER PILOT SCALE PROGRAM EXPERIENCE

Facility	Vendor(s)	Sorbents Tested	Comments
Leland Olds Station	Atomics International/ Wheelabrator-Frye Carborundum Company	Soda ash, trona, lime, limestone, and ammonia	Two-month pilot testing 3000 actm size 100 hr continuous tests up to 90% SO_2 reduction reported[12]
Hoot Lake Station	Joy/Niro	Soda ash, fly ash, lime, etc.	Pilot plant testing at 20,000 acfm size 100 hr continuous run
W.J. Neal Station	Babcock & Wilcox	Soda ash, fly ash, lime	3000 acfm pilot testing 100 hr continuous tests up to 90% SO_2 reduction reported

TABLE 3-6

TYPICAL FUEL CHARACTERISTICS

Sulfur, %	0.54
Moisture, %	28.92
Ash, %	7.89
High Heating Value, BTU/lb	8139

TYPICAL ASH ANALYSES

Compound	Average Weight Percent
SiO_2	35.58
Al_2O_3	16.82
CaO	20.27
MgO	3.45

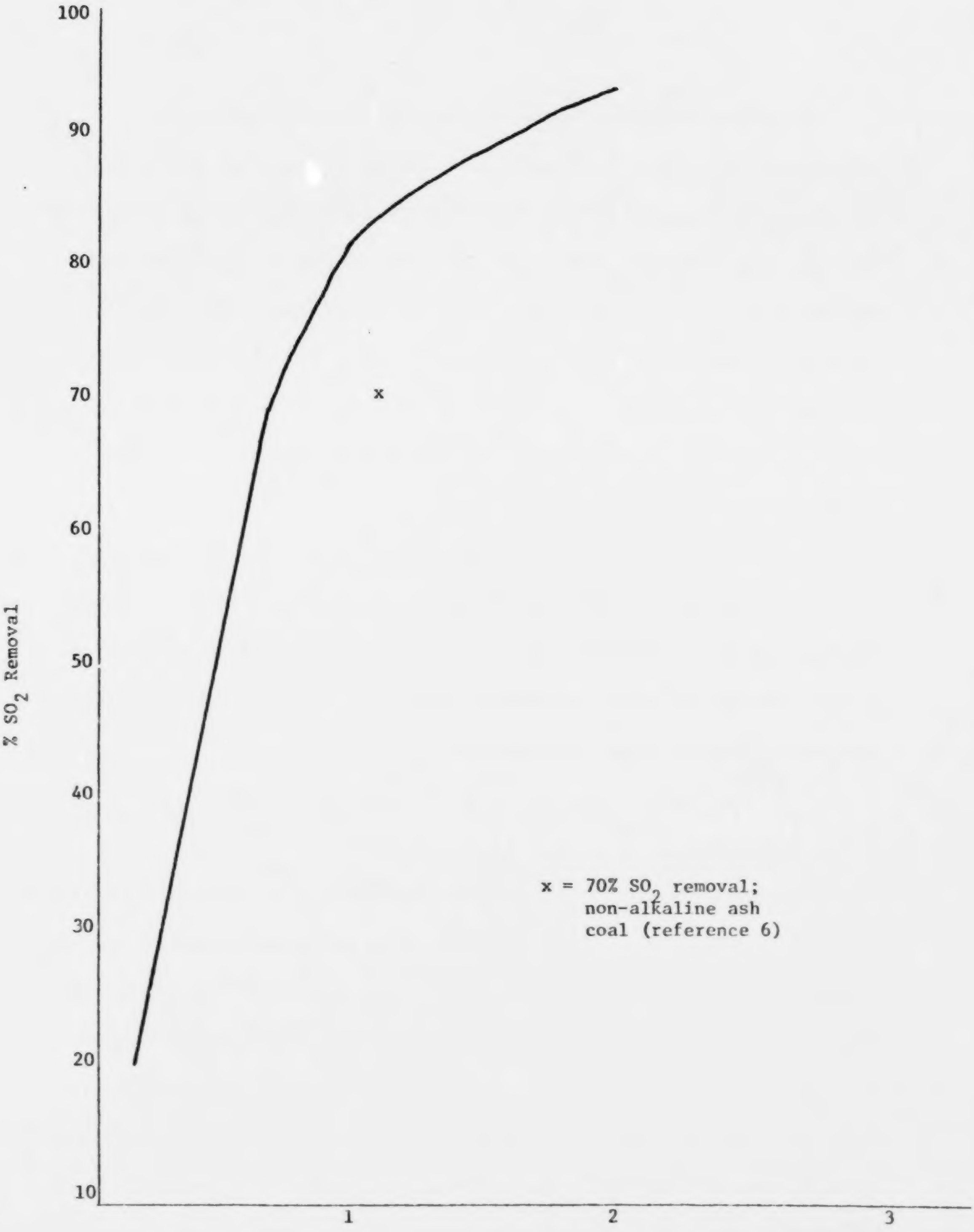


FIGURE 3-27

PERCENT SO_2 REMOVAL AND STOICHIOMETRIC RATIO FOR ALKALINE ASH COALS[5]

To demonstrate the impact of the alkalinity on effective stoichiometric ratio, the stoichiometric ratio has been calculated based upon 50 percent of the fly ash lime being chemically available and the lime addition rate. For the coal listed in Table 3-6, and a 550 MWe boiler, the stoichiometric ratio based upon lime addition rate and entering SO_2 is 1.12. The fly ash, assuming 50 percent availability of the lime, would contribute to the stoichiometric ratio an additional 0.8 units. The effective stoichiometric ratio within the spray dryer would be 1.92.

The significance of stoichiometric ratio becomes apparent when the operating and maintenance component of the total annual revenue requirement is estimated. As the stoichiometric ratio increases at a constant sulfur oxide percentage reduction requirement, the reagent and waste disposal cost also increase.

3.4.3 Economics

Since dry SO_2 scrubbing systems combine sulfur oxide and particulate matter control into a single process. The projected costs of dry SO_2 control are based upon the incremental flue gas desulfurization cost. The cost was estimated by extracting the particulate control costs from the published total capital cost.[7] The cost of a spray dryer flue gas desulfurization system exclusive of particulate control costs is estimated at $30-40/KW. Table 3-7 is an estimate of the operating and maintenance costs for a typical dry SO_2 control system for a

Table 3-7 - Economics of Dry SO_2 Control

	Coal Sulfur Content #SO_2/MM BTU		
	1.68	2.3	4.0
Total Capital Investment $ KW	30.30	30.30	30.30
O&M Costs			
Lime	2,678,000	3,666,000	6,376,000
Labor	454,000	454,000	454,000
Replacements	500,000	500,000	500,000
Power Costs	213,000	213,000	213,000
Disposal	525,000	718,000	1,250,000
TOTAL	4,370,000	5,551,000	8,793,000
O&M Mills/KWH	1.5	1.9	3.1

Based Upon: 500 MWe Plant, 70% Removal
65% Load Factor
$40/Ton of Lime
$5/Ton Waste Disposal Cost
Non-Alkaline Ash (1977 Dollars)

variety of coal sulfur contents. At a constant percentage reduction, Table 3-7 shows the impact of increasing reagent and waste disposal costs. The lime and waste disposal cost expressed as a fraction of the total O&M cost increases from 73 to 87 percent as the coal sulfur content increases from 1.68 to 4.0 pounds of SO_2 per million BTU.

An economic comparison between wet and dry flue gas desulfurization processes is given in Figure 3-28 for alkaline coals. The coal sulfur characteristics which are used in the EPA economic model are described in Table 3-8. At 70 and 85 percent removal, dry SO_2 control systems are less costly than wet scrubbers for alkaline ash coals. The economic comparison between wet and dry flue gas desulfurization systems for non-alkaline coals is given in Figures 3-29 and 3-30 for 70 and 80 percent SO_2 control respectively. Based on the data available, 70 percent SO_2 reduction using dry SO_2 control technology appears to be less costly than wet scrubbers for coals which contain less than about 3.5 pounds of SO_2 per million BTU. If the level of control is increased to 80 percent, the maximum coal sulfur content which can be economically treated by dry SO_2 control systems decreases to about 3 pounds of SO_2 per million BTU.

Since all of the published test results are for alkaline coals, the uncertainty in the stoichiometric ratio which is required to achieve a 70 percent reduction for nonalkaline coals is larger than for alkaline coals. This uncertainty could have a significant impact on the O&M costs because the reagent and waste disposal costs are about 70-85 percent of the operating and maintenance requirements. An error of

Table 3-8

REPRESENTATIVE COALS USED IN EPA's ECONOMIC MODEL

Designation	Pounds of SO2/ Million BTU	Coal Sulfur Content, %	Coal Rank
A	0.8	0.4	Subbituminous
B	1.2	0.6	Subbituminous
D	1.7	0.68-0.8	Subbituminous, bituminous lignite
F	3.3	1.32-1.65	Subbituminous, bituminous lignite
G	5.0	2.5	Bituminous
H	greater than 5.0	greater than 2.5	Bituminous

Economic Comparison Between Wet and Dry FGD Processes
AT 70% SO2 Removal (Alkaline Ash)

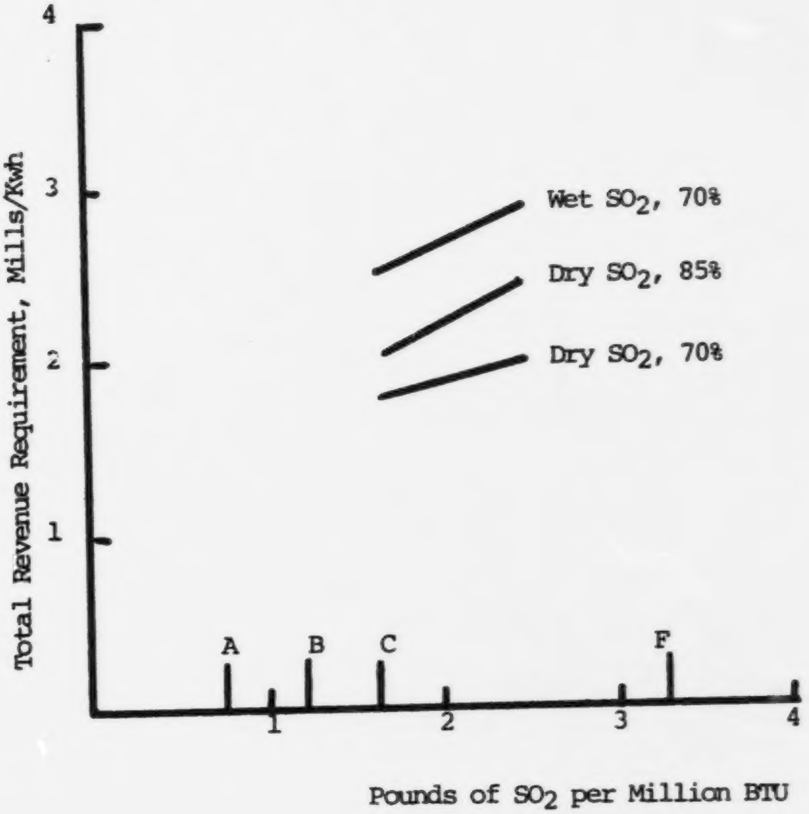


FIGURE 3-28

Economic Comparison Between Wet and Dry FGD Processes at 70% SO_2 Removal (Non-Alkaline Ash)

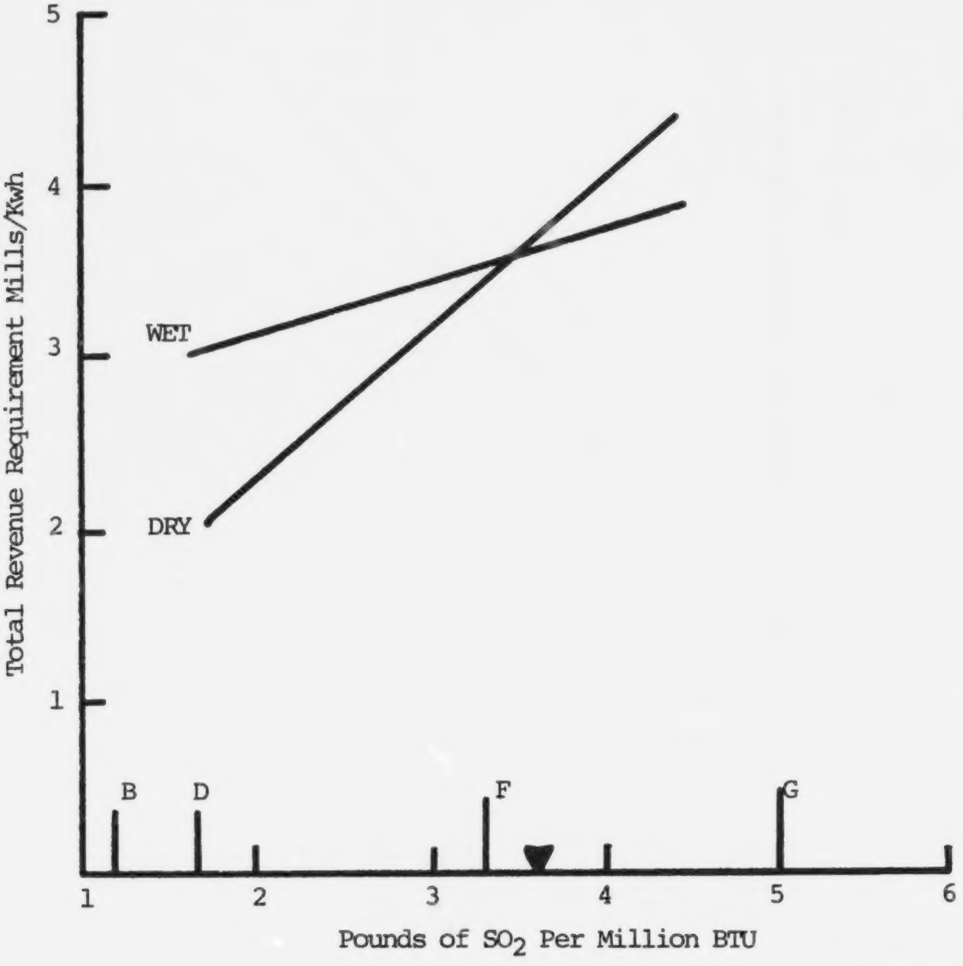


FIGURE 3-29

Economic Comparison Between Wet and Dry FGD Processes
at 80% Removal (Non-Alkaline Ash)

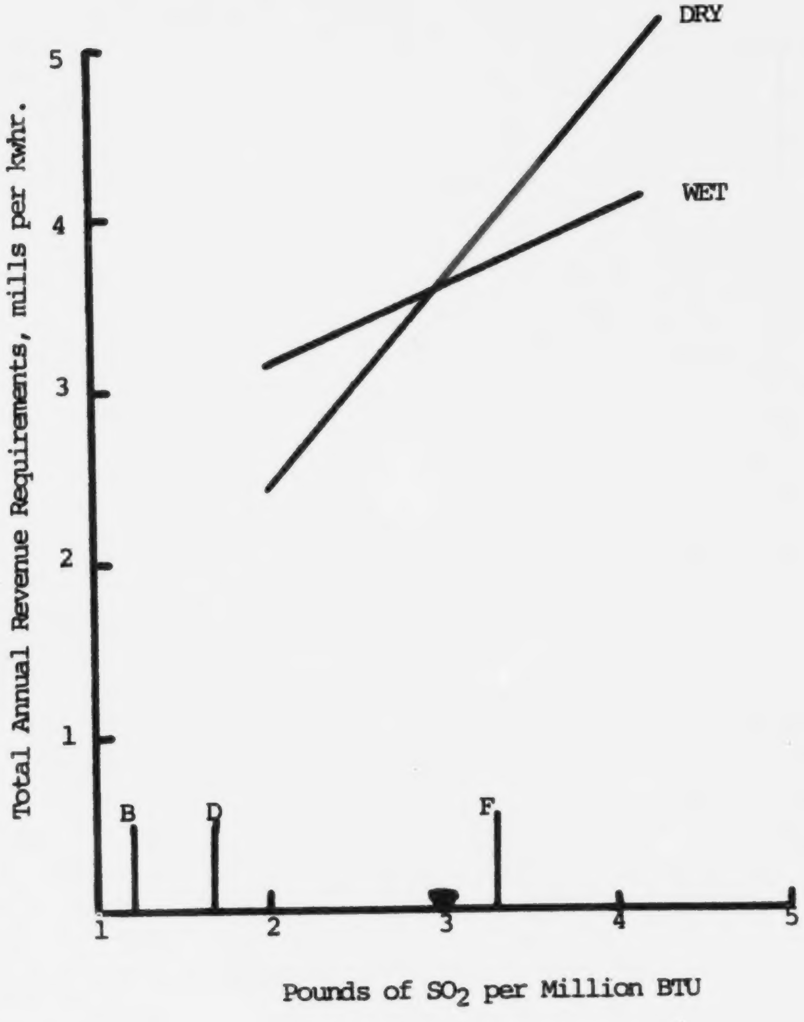


FIGURE 3-30

10 percent in the stoichiometric ratio could reduce the maximum coal sulfur content which could be economically treated by dry SO_2 control from 3.0 to about 2.6 pounds of SO_2 per million BTU, a 13.3% reduction in the maximum coal sulfur content (see Figure 6).

3.4.4 Environmental and Energy Impacts

In addition to lower costs, dry SO_2 control offers other advantages over wet scrubbers. These advantages include:

a. The dry system requires no wet sludge handling equipment. Although the amount of waste produced on a dry basis is larger for a dry scrubber than a wet system, it appears to be easier to dispose of and handle.

b. The dry system requires approximately 25 to 50 percent of the energy required for a wet system.

c. The dry scrubber will use about 30 to 50 percent of the amount of water required for the wet systems.

d. Although reliability data on dry systems are limited, due to the simplicity of the flow sheet, dry systems could have availabilities significantly higher than for conventional wet limestone scrubbers.

Because of its economic advantages and potential for increased reliability, the dry SO_2 control system has attracted utility and industrial interest. To date, five systems have been ordered. Two of the systems are for industrial boilers and three of the systems are for utility boilers. A listing of the "on order" dry SO_2 control system is given in Table 3-9.

Uncertainty in Economic Comparisons

At 70% SO2 Removal

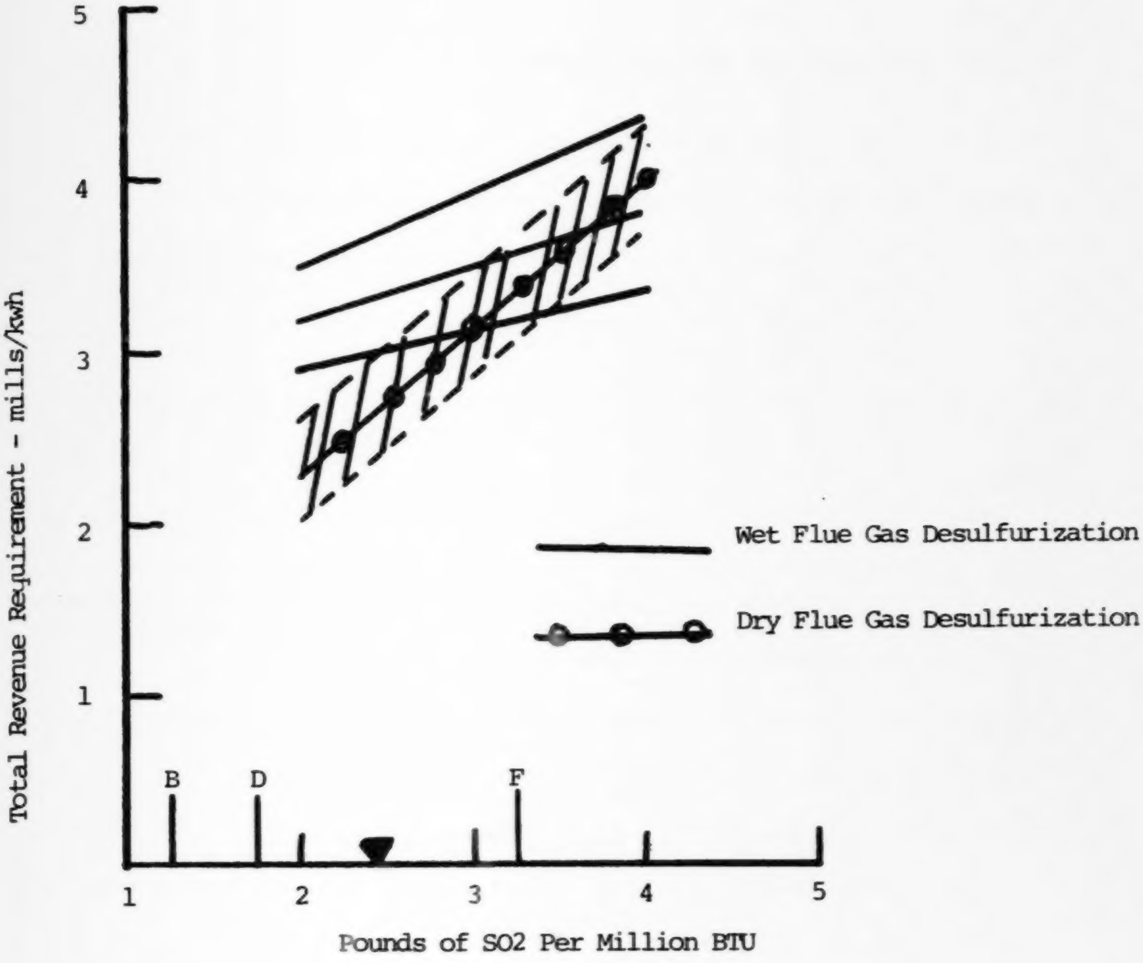


FIGURE 3-31

TABLE 3-9

Dry SO2 Control Systems on Order

Utility/Company	Station/Plant	Capacity (MW/SCFM)	Coal Sulfur Lb. of SO_2/Mill.Btu	Status	Start up Date	Longterm % of SO2 Removal
Basin Electric Power Coop	Antelope Valley 1	455 MW	2.1	Contract Awarded	11/81	78
Basin Electric Power Coop	Laramie River 3	550 MW	2.0	Contract Awarded	4/82	85
Otter Tail Power	Coyote 1	400 MW	2.4	Under Construction	5/81	50
Celanese Corp.	Cumberland Plant	57,700 SCFM	1.7	Contract Awarded	12/79	70
Strathmore Paper Company	Woronoco Plant	22,000 SCFM	N/A	Under Construction	5/79	N/A

3.4.5 References

1. Estcourt, V.F., Crutle, R.O.M., Gehri, D.C., and Peters, H.J. Tests of a Two-Stage Combined Dry Scrubber/SO_2 Absorber Using Sodium or Calcium. Presented at the 40th Annual Meeting American Power Conference, Chicago, Illinois, 26 April 1978.

2. Personal communication from R. Eriksen, Basen Electric. Power Cooperative.

3. Janssen, E. and Eriksen, R.L.. Basin Electric's Involvement with Dry Flue Gas Desulfurization, 5th Symposium on Flue Gas Desulfurization, Las Vegas, Nevada, 5-8 March 1979.

4. Letter to Mr. Fred Longenberger from Mr. R.L. Eriksen, 21 November 1978.

5. The Dry Scrubber for Flue Gas Desulfurization and Particulate Control, Niro Atomizer/Joy Manufacturing Company.

6. Pirstenberg, H. Prevention of Significant Deterioration Application for the Installation of a Coal-Fired Boiler and Associated Facilities at the Amcelle Plant in Cumberland, Maryland, NUS-3232.

7. Personal communication from B. Laski, PEDCO Environmental.

4. PARTICULATE

4.1 INTRODUCTION

On September 19, 1978, EPA proposed revised standards for particulate matter. The proposal was based on the particulate matter emission test data contained in the Background Information Document (BID-proposal) for the particulate matter emission standard (EPA 450/2-78-006a). The BID included data on many subjects relative to particulate matter emissions from electric utility steam generating units including performance data on ESP systems, baghouse systems, scrubber systems, FGD slurry carryover, and sulfuric acid mist condensation.

In the September 19, 1978 proposal EPA indicated that it would continue to investigate two areas of the particulate matter data base; (1) performance of the new 350 MW baghouse controlled utility steam generating unit that recently initiated operation, and (2) the potential interference of acid mist with the measurement of particulate matter.

4.2 LARGE BAGHOUSE CONTROL SYSTEMS

At the time these regulations were proposed, the largest baghouse-controlled coal-fired steam generator for which EPA had particulate matter emission test data had an electrical output of 44 MW. Several larger baghouse installations were under construction and two larger units were initiating operation. Since the date of proposal of these standards, EPA has tested one of the new units. It has an electrical output capacity of 350 MW and is fired with pulverized, subbituminous coal containing 0.3 percent sulfur. The ng/J (0.1 lb/million Btu) heat input emission limit. This unit has achieved emission levels below 13 ng/J (0.03 lb/million Btu) heat input. The baghouse control system was designed with an air-to-cloth ratio of 1.0 actual cubic meter per minute per square meter (3.32 ACFM/ft^2)

and a pressure drop of 1.25 kilopascals (5 in H_2O). Although some operating problems have been encountered, the unit is being operated within its design emission limit and the level of the standard. During the testing the power plant operated in excess of 300 MW electrical output. Work is continuing on the control system to improve its performance. Regardless of type, large emission control systems generally require a period of time for the establishment of cleaning, maintenance, and operational procedures that are best suited for the particular application. The data for each test run obtained for the facility are summarized in the Table 4-1.

TABLE 4-1

Stack Emission Rate $lb/10^6$ BTU	Efficiency Percent	Electrical Load MW
.018	99.35	362
.016	99.36	362
.024	99.25	362
.007	99.71	362
.035	99.16	306

4.3 PERFORMANCE TESTING - ACID MIST

EPA indicated in the September 19, 1978, proposal that it would continue to investigate the suspected problem of acid mist interference with Method 5 performance testing. Such a situation was suspected to occur when testing after an FGD system when a facility was firing high sulfur coal.

Since proposal, EPA conducted a series of tests on a 181 MW boiler burning 3% sulfur coal and equipped with an electrostatic precipitator designed for 98.6 percent particulate removal, followed by an SO_2 scrubber using carbide lime slurry. Although this facility was not considered the best control technology for particulate, it was adequate for demonstrating the potential problem of acid mist interference with particulate measurement techniques.

A set of tests were run in the stack following the SO_2 scrubber using the two proposed performance test methods - EPA Method 17 which uses an in-stack filter and EPA Method 5 sampling train which uses an out-of-stack heated filter. The results of these tests are summarized in Table 4-2 below. Since these tests were run for the purpose of comparing methods, the samples were taken at a single point in the stack.

TABLE 4-2

		Emission Rate lb/10^6BTU			
TEST METHOD SAMPLING TRAIN	FILTER TEMPERATURE (°F)	Run Number 1	2	3	Average
EPA 17	Stack (~155)	0.0905	0.1470	0.0927	0.1127
EPA 5	320	0.0986	0.0895	0.0953	0.0945
EPA 5	340	0.0714	0.0534	0.0577	0.0608

Following the series of acid mist evaluation tests, EPA obtained data from a compliance test conducted at a 194 MW boiler burning 3 to 4% sulfur coal and equipped with an electrostatic precipitator designed for 99.6 precent particulate removal followed by a limestone SO_2 scrubber. Although no tests were conducted at this facility to evaluate the affect of sampling temperature on the amount of particulate measured, the stack emissions following the scrubber were measured using EPA Method 5 at a filter temperature of 320°F with no apparent acid mist problem in meeting the final standard of 0.03 lb/10^6BTU. The results of this test are summarized below in Table 4-3:

TABLE 4-3

Run #	Electrical Load MW	Stack Emission Rate lb/10^6 BTU	Scrubber Inlet Emission Rate lb/10^6 BTU	ESP Inlet Emission Rate lb/10^6 BTU	Precipitator Collection Efficiency
1	190	0.0201	0.0203	6.99	99.71
2	185	0.0141	0.0165	7.63	99.78
3	192	0.0209	Not measured	Not measured	Not Measured

5. NITROGEN OXIDES

5.1 INTRODUCTION

In developing the final NO_x standards, the Administrator considered emission data and other new information received after proposal of the standards. Some of this information was submitted with comment letters received during the public comment period, while other information was requested by the Administrator. This new information is discussed below.

5.2 INFORMATION RECEIVED AFTER PROPOSAL

The Administrator received a number of comment letters which criticize the proposed 24-hour emissions averaging period for coal, arguing that it would not give boiler operators the flexibility they need to handle normal boiler problems which occur during day-to-day operation. As an aid in evaluating the emission variability expected during normal operation of a boiler, the Administrator has evaluated approximately 34 months of continuously monitored NO_x data from seven coal-fired boilers. The boilers are described in Table 5-1 and the continuously monitored NO_x data appear in Table 5-2. All but six months of these data were received after proposal of the standards.

Table 5-1. PLANTS SUBMITTING CONTINUOUSLY MONITORED NO_X EMISSION DATA

Station[1] and Company	Coal[2]	Boiler Manufacturer	Electrical Output, MW	Monitor Certification Date
Colstrip #1, Montana Power	SUBB	CE[3]	350	Not Certified[5]
Colstrip #2, Montana Power	SUBB	CE	350	Not Certified[5]
Harrington #1, Southwestern Public Service	SUBB	CE	360	7/78
Muskogee #4, Oklahoma Gas and Electric	SUBB	CE	550	2/78
Boiler #4, Adolph Coors	SUBB	CE	(25)[4]	11/77
Huntington Canyon #1, Utah Power and Light	W BIT	CE	430	3/78
Ghent #1, Kentucky Utilities	E BIT	CE	510	9/78

---

[1] All boilers are required to comply with a NO_X emission limit of 300 ng/J (0.7 lb/million Btu) heat input.

[2] SUBB is subbituminous coal; W BIT is Western bituminous coal; E BIT is Eastern bituminous coal.

[3] CE is Combustion Engineering, Incorporated.

[4] This boiler does not generate electricity. Its input rate is about 73 MW (250×10^6 Btu/hr). If electricity were generated, 73 MW input would generate roughly 25 MW electrical output.

[5] Although these monitors are not certified, in April and June of 1978 the monitors' performance was evaluated by EPA and determined to be satisfactory. The monitor data appear to be biased high, but probably by less than 21 ng/J (0.05 lb/million Btu).

Table 5-2. SUMMARY OF CONTINUOUSLY MONITORED NO_x EMISSION DATA

Station and Company	Month and Year	Days of Useful Data[1]	Monthly Average NO_x Emissions[2]		24-hour Periods Above:[3]		
			ng/J	(lb/million Btu)	210	260	300 ng/J
Colstrip #1, Montana Power	10-77	28	205	(0.48)	15	2	0
	11	30	175	(0.41)	2	0	0
	12	31	155	(0.36)	1	0	0
"	1-78	31	140	(0.33)	0	0	0
	2	28	130	(0.30)	0	0	0
	3	30	140	(0.33)	0	0	0
	4	28	140	(0.32)	0	0	0
"	5	0	-	-	-	-	-
	6	27	135	(0.31)	0	0	0
	7	25	170	(0.39)	1	0	0
"	8	19	170	(0.39)	3	1	0
	9	28	195	(0.45)	7	1	0
	10	31	205	(0.48)	16	1	0

Table 5-2. SUMMARY OF CONTINUOUSLY MONITORED NO_x EMISSION DATA (continued)

Station and Company	Month and Year	Days of Useful Data[1]	Monthly Average NO_x Emissions[2]		24-hour Periods Above:[3]		
			ng/J	(lb/million Btu)	210	260	300 ng/J
Colstrip #2, Montana Power	10-77	14	185	(0.43)	1	0	0
	11	24	145	(0.34)	0	0	0
	12	31	160	(0.37)	1	0	0
"	1-78	22	170	(0.39)	2	0	0
	2	27	190	(0.44)	4	0	0
	3	17	130	(0.30)	3	0	0
"	4	4	140	(0.33)	0	0	0
	5	30	185	(0.43)	5	1	0
	6	29	240	(0.56)	25	5	0
	7	28	230	(0.53)	21	6	0
"	8	26	240	(0.56)	26	7	0
	9	27	205	(0.48)	12	0	0
	10	31	180	(0.42)	5	0	0

Table 5-2. SUMMARY OF CONTINUOUSLY MONITORED NO_X EMISSION DATA (continued)

Station and Company	Month and Year	Days of[1] Useful Data	Monthly Average NO_x Emissions[2] ng/J	(lb/million Btu)	24-hour Periods Above:[3] 210	260	300 ng/J
Harrington #1, Southwestern Public Service	7-78	17	190	(0.44)	3	0	0
	8	17	235	(0.55)	14	2	0
"	9	3	250	(0.58)	2	1	0
Muskogee #4, Oklahoma Gas and Electric	2-78	21	200	(0.46)	4	0	0
	3	15	155	(0.36)	0	0	0
Boiler #4, Adolph Coors	10-77	5	305	(0.71)	5	5	4
	11	15	335	(0.78)	15	15	15
"	12	27	325	(0.76)	27	27	19
	1-78	1	245	(0.57)	1	0	0

Table 5-2. SUMMARY OF CONTINUOUSLY MONITORED NO_X EMISSION DATA (continued)

Station and Company	Month and Year	Days of Useful Data[1]	Monthly Average NO_x Emissions[2] ng/J	(lb/million Btu)	24-hour Periods Above:[3] 210	260	300 ng/J
Huntington Canyon #1, Utah Power and Light	2-78	14	225	(0.52)	7	0	0
	3	8	260	(0.60)	8	4	0
Ghent #1, Kentucky Utilities	2-79	26	220	(0.51)	14	0	0
	3	9	190	(0.44)	0	0	0

[1] Some months contain less than 30 days of useful data. This is because during these months the boiler or the NO_x monitor was out of service for periods of time greater than 24 hours.

[2] This is the average of all 24-hour averages of NO_x data available during the calendar month. Some 24-hour periods contain less than 24 hours of useful data due to the boiler or the NO_x monitor being out of service.

[3] Listed are the number of 24-hour averages of NO_x data which are above the specified emission limits during the calendar month. All boilers listed in the table are required under 40 CFR Part 60, Subpart D to comply with a NO_x limit of 300 ng/J (0.7 lb/million Btu) heat input. If construction of the boilers had commenced after September 18, 1978, however, the boilers would be subject under 40 CFR Part 60, Subpart Da to the lower limits indicated. The 260 ng/J (0.6 lb/million Btu) limit applies to new electric utility boilers which burn bituminous coal, and the 210 ng/J (0.5 lb/million Btu) limit applies to new electric utility boilers which burn subbituminous coal.

All of the continuously monitored NO_x data were collected by plant personnel as part of a regular monitoring program. Although EPA has not evaluated all of these monitoring programs, it is believed that the data accurately reflect the range of emissions expected during normal operation of the boilers. This is because (1) five of the seven boilers have NO_x monitors which have passed certification tests; and (2) the other two boilers, located at Colstrip, Montana, have monitors which have been thoroughly evaluated by EPA. The Colstrip monitors appear to be biased high, but by no more than about 21 ng/J (0.05 lb/million Btu) heat input.[1] Thus, the Administrator considers the Colstrip data useful in evaluating emission variability during day-to-day operation.

The continuously monitored data are from boilers which are required by EPA regulations (40 CFR Part 60, Subpart D) to comply with a NO_x emission limit of 300 ng/J (0.70 lb/million Btu) heat input. The boilers were not required to operate at lower NO_x levels during the periods of time when data were submitted. Nevertheless, it appears that most of the boilers were operated at somewhat lower levels. The Administrator considers these data useful in evaluating the emissions averaging period because they indicate the emission variability to be expected during day-to-day operation of a utility boiler. Also, the data are useful in that they generally support the final NO_x standards for bituminous and subbituminous coals.

The continuously monitored NO_x emission data from the Adolph Coors boiler are unusually high. These emission levels are atypical of normal operation because the data were purposely selected to represent periods of time when emissions were highest. Ordinarily, emission levels are below the applicable NO_x standard for this boiler of 300 ng/J (0.70 lb/million Btu) heat input. Sometimes, however, it is necessary to supplement the fuel with natural gas to maintain these levels. The Adolph Coors Company is uncertain about why NO_x emissions from this boiler are higher than expected, necessitating the periodic use of natural gas. The Company speculates that their special boiler design which is needed to burn an unusually dirty coal supply may encourage NO_x formation.

---

[1] EPA Memorandum. Winton Kelly to Files (78-SPP-27). Review of Available NO_x Data from Colstrip Units 1 and 2, Montana Power Company. March 13, 1979. EPA Docket Number IV-B-49.

While contacting electric utilities for continuously monitored NO_x data, the Administrator received performance test results from two utilities. These data are presented in Table 5-3. A performance test is conducted with standardized EPA test methods and is used to determine whether a new boiler is initially in compliance with EPA standards. The Administrator has also received emission data used to determine the relative accuracy of a continuous NO_x monitor. These data are presented in Table 5-4.

On November 8 and 9, 1978, at the Second EPRI NO_x Control Technology Seminar in Denver, Colorado, technical papers were presented by the four major boiler manufacturers. These papers

Table 5-3. PERFORMANCE TEST DATA

Station[1] and Company	Columbia #2, Wisconsin Power and Light	Morrow #1, South Mississippi Electric Power
Coal	Subbituminous	Bituminous
Boiler Manufacturer	Combustion Engineering	Riley Stoker
Electrical Output, MW	520	220
Performance Test Date	May 16, 1978	October 11, 1978
NO_x Emissions,[2] ng/J (lb/million Btu)		
Test #1	255 (0.59)	210 (0.49)
Test #2	260 (0.61)	135 (0.31)
Test #3	260 (0.61)	115 (0.27)
Average	260 (0.60)	155 (0.36)

[1] These boilers are required to comply with a NO_x emission limit of 300 ng/J (0.7 lb/million Btu) heat input.

[2] Each test was performed using EPA Reference Method 7 and consists of the average of four individual concentration measurements (grab samples). A "performance test" is defined as the average of three individual tests and is used to determine compliance with EPA emission limits.

Table 5-4. REFERENCE METHOD TEST DATA

Station[1] and Company	Presque Isle #7, Upper Peninsula Generating
Coal	Bituminous
Boiler Manufacturer	Riley Stoker
Electrical Output, MW	80
Test Date	October 6 & 7, 1978
NO_x Emissions,[2] ng/J (lb/million Btu)	
Test #1	215 (0.50)
Test #2	215 (0.50)
Test #3	260 (0.60)
Test #4	225 (0.52)
Test #5	225 (0.52)
Test #6	200 (0.47)
Test #7	220 (0.51)
Test #8	225 (0.52)
Test #9	205 (0.48)

[1] This boiler is required to comply with a NO_x emission limit of 300 ng/J (0.7 lb/million Btu) heat input.

[2] Each test was performed using EPA Reference Method 7 and consists of the average of three individual concentration measurments (grab samples). The tests were used to determine the relative accuracy of the continuous monitoring system. (The continuous monitor data are not presented here.)

were considered by the Administrator in developing the final NO_x standards and are referenced as footnotes 1-4.

Due to the large number of comment letters received it was impossible for the Administrator to address in the preamble to final standards all issues raised in the comment letters, or to present in this document all of the new information received. Nevertheless, all comments and new information, as well as EPA memorandum relevant to the final NO_x standards, may be examined in the docket. (The docket is open for public review, as explained in the preamble to the final standards.) The most detailed comments on the proposed NO_x standards were prepared by KVB, Incorporated, for the Utility Air Regulatory Group.[5]

---

[1] Barsin, J. A. Pulverized Coal Firing NO_x Control. Babcock and Wilcox Company, Barberton, Ohio. EPA Docket Number IV-B-21.

[2] Marshall, J. J., and A. P. Selker. The Role of Tangential Firing and Fuel Properties in Attaining Low NO_x Operation for Coal-Fired Steam Generation. Combustion Engineering, Inc., Windsor, Connecticut. EPA Docket Number IV-B-21.

[3] Rawdon, A. H., R. A. Lisauskas, and F. J. Zone. Design and Operation of Coal-Fired Turbo Furnaces for NO_x Control. Riley Stoker Corporation, Worcester, Massachusetts. EPA Docket Number IV-B-21.

[4] Vatsky, J. Experience in Reducing NO_x Emissions on Operating Steam Generators. Foster Wheeler Energy Corporation, Livingston, New Jersey. EPA Docket Number IV-B-21.

[5] Evaluation of the Proposed NSPS for NO_x Emissions from Coal Fired Utility Boilers. KVB, Incorporated, Houston, Texas. Report Number 24300-390/R2. January 1979. (Prepared for the Utility Air Regulatory Group.) EPA Docket Number IV-D-611.

6. ENVIRONMENTAL IMPACT STATEMENT SUMMARY

6.1 INTRODUCTION

On September 19, 1978 (43 FR 42154), the Administrator proposed standards of performance for new, modified, and reconstructed electric utility steam generating units under the authority of the 1977 Clean Air Act Amendments. That action was accompanied by publication of a draft Environmental Impact Statement consisting of the following four documents:

A. "Electric Utility Steam Generating Units: Background Information for Proposed NO_x Emission Standards," EPA 450/2-78-005a;

B. "Electric Utility Steam Generating Units" Background Information for Proposed Particulate Matter Emission Standards," EPA 450/2-78-006a;

C. "Electric Utility Steam Generating Units: Background Information for Proposed SO_2 Emission Standards," EPA 450/2-78-007a; and

D. "Electric Utility Steam Generating Units: Background Information for Proposed SO_2 Emission Standards - Supplement," EPA 450/2-78-007a-1.

Notice of the draft Environmental Impact Statement's availability was also published in the Federal Register on December 4, 1978 (43 FR 56722).

This document is the final Environmental Impact Statement (document E in Table 6-1) which updates the draft statement. A cross-index to the information developed prior to the Administrator's final action is contained in Table 6-1. This table provides an index to the Background Information documents (listed above), other information documents (listed in section 6.3), and Federal Registers which describe the alternative actions considered and their impacts.

6.2 PUBLIC COMMENTS

Over 700 comments were received on the proposed regulations. A summary of these comments is given in section 2 of this document. Revisions were made to the proposed regulations in response to these comments. A description of these revisions, an analysis of suggested revisions which were not made, and the rationale for the final action taken by the Administrator are presented in the preamble to the promulgated regulations.

6.3 ENVIRONMENTAL IMPACTS

The following studies were done prior to proposal to investigate the impact of applying flue gas desulfurization systems to new, modified, and reconstructed electric utility steam generating units:

1. "Flue Gas Desulfurization Systems: Design and Operating Parameters, SO_2 Removal Capabilities, Coal Properties and Reheat."
2. "Flue Gas Desulfurization System Capabilities for Coal-Fired Steam Generators."
3. "Boiler Design and Operating Variables Affecting Uncontrolled Sulfur Emissions from Pulverized Coal-Fired Steam Generators."
4. "Effects of Alternative New Source Performance Standards on Flue Gas Desulfurization System Supply and Demand."
5. "Evaluation of Physical Coal Cleaning as an SO_2 Emission Control Technique."
6. "The Impact of Modification/Reconstruction of Steam Generators on SO_2 Emissions."

7. "The Energy Requirements for Controlling SO_2 Emissions from Coal-Fired Steam/Electric Generators."

8. "The Solid Waste Impact of Controlling SO_2 Emissions from Coal-Fired Steam-Electric Generators."

9. "Water Pollution Impact of Controlling SO_2 Emissions from Coal-Fired Steam/Electric Generators."

10. "Particulate and Sulfur Dioxide Emission Control Costs for Large Coal-Fired Boilers."

11. "Review of New Source Performance Standards for SO_2 Emissions from Coal-Fired Utility Boilers."

12. "The Effect of Flue Gas Desulfurization Availability on Electric Utilities."

13. "Effects of Alternative New Source Performance Standards for Coal-Fired Electric Utility Boilers on the Coal Markets and Utility Capacity Expansion Plans."

14. "Flue Gas Desulfurization System Manufacturers Survey."

15. "Assessment of Manufacturer Capacity to Meet Requirements for Particulate Control in Utility and Industrial Boilers."

16. "Flue Gas Desulfurization Cost for Large Coal-Fired Boilers, August 10, 1978."

17. "The Ability of Electric Utilities with FGD to Meet Energy Demands."

These studies describe the impacts of applying wet system FGD technology for control of SO_2 emissions. In addition to these studies, further analyses of the impacts of using dry as well as wet SO_2 control systems have been completed. The preamble to the promulgated regulations gives the impacts of wet and dry controls for the final alternatives considered. A discussion of dry controls is presented in section 3.4 of this document.

The ICF Incorporated Coal and Electric Utilities Model has been used to evaluate the impacts of all alternatives considered. The results of the ICF computer analyses and a description of alternatives considered are presented in the preamble to the proposed standards (43 FR 42154), a correction notice published November 27, 1978 (43 FR 55258), a notice published December 8, 1978 (43 FR 57834), the preamble to the promulgated regulations, and the docket.

6.4 SUMMARY OF IMPACTS FOR FINAL ALTERNATIVES CONSIDERED

The preamble to the promulgated regulations discusses the final alternatives considered. With the alternative selected, dry or wet SO_2 control systems can be used on low-sulfur coals and wet systems can be used on all other coals. Dry control systems, which are more cost-effective on low-sulfur coals, reduce the water, solid waste, energy, and economic impacts of the final standards relative to the proposed standards. The environmental impacts of wet and dry SO_2 control systems and NO_x and particulate matter control systems are summarized in Table 6-2. This table illustrates the impacts of (1) not revising the current standards, (2) the proposed standards, and (3) the final standards relative to a baseline of no emission control at all. The current standards had negligible water, solid waste, energy, and economic impacts because compliance with about two-thirds of all new units currently under construction is being achieved by use of low-sulfur coal rather than FGD systems. The final standards, which apply to all new units that commence construction after September 19, 1978, will result in less air pollution emissions and small, incremental increases in solid waste, energy, and economic impacts due to the application of scrubbing equipment. In the analyses of environmental impacts, all new facilities affected by the revised standards were assumed to have installed SO_2 control equipment.

Table 6-1

Environmental Impact Cross-Index

Agency Guidelines for Preparing Regulatory Action Environmental Impact Statements (39 FR 37419)	Location Within Documents
Background and description of proposed action.	A summary of the background is given in Chapter 1 of documents A, B, C, and E.
Summary of proposed standards.	A summary of the proposed standards is given in the *Federal Register* (43 FR 42154).
Statutory basis for proposed standards.	The statutory authority is summarized in section 2.1 of documents A and B and section 1.2 of document C.
Facilities affected by the standards.	A description of the affected facility is given in chapter 3 of documents A and B, section 5.1 of document C, and the proposed and final *Federal Register* notices.
Availability of control.	Information on available emission control systems is given in chapter 4 of documents A, B, C, and D and chapters 3 and 4 of document E.
Alternatives to the action taken.	Alternatives considered in development of the regulations are given in chapter 6 of documents A and B, chapter 4 of document C, chapters 2 and 3 of document D, and in the *Federal Register* (43 FR 42154, 43 FR 55258, 43 FR 57834, and the preamble to the final action). Additional analyses are contained in the docket (OAQPS-78-1).
Costs and economic impacts.	Cost analyses and economic impacts of the alternatives considered are given in chapter 8 of documents A and B, chapter 7 of document C, chapters 2 and 3 of document D, chapter 3.4.3 of document E, and in the *Federal Register* (43 FR 42154, 43 FR 55258, 43 FR 57834, and the preamble to the final action).

Table 6-1
(continued)

Environmental Impact Cross-Index

Agency Guidelines for Preparing Regulatory Action Environmental Impact Statements (39 FR 37419)	Location Within Documents
Air quality impacts.	The effects on air quality are described in section 7.2 of document A, 7.1 of document B, and section 6.2 of document C. Estimated national emissions of each alternative considered are given in chapters 2 and 3 of document D, and in the Federal Register (43 FR 42154, 43 FR 55258, 43 FR 57834, and the preamble to the final action).
Water impacts.	The water quality impacts are given in section 7.3 of documents A and B, section 6.3 of document C, and in document 9.
Solid waste impacts.	The solid waste impacts are given in section 7.3 of document A, section 7.2 of document B, section 6.4 of document C, and in document 8 and the preamble to the final action.
Energy impacts.	The energy impacts are discussed in section 7.3 of document A, Section 7.4 of document B, section 6.6 of document C, sections 2.4.2 and 3.2.2 of document D, document 7, and in the Federal Register (43 FR 42154, 43 FR 55258, 43 FR 57834, and the preamble to the final action).
Other impacts.	The impacts upon coal, noise, and other areas are given in section 7.3 of document A, section 7.5 of document B, sections 6.5, 6.7, and 6.8 of document C, sections 2.4.1 and 3.2.3 of document D, documents 4, 12, and 13, and in the Federal Register (43 FR 42161, 43 FR 55258, 43 FR 57834, and the preamble to the final action).
Impacts of action taken.	The air, water, solid waste, energy, economic, and other impacts of the alternative selected are dicussed in the preamble to the final action.

Table 6-2

Matrix of Environmental and Economic Impacts of Regulatory Alternatives Relative to a Baseline of No Control

Administrative Action	Air Impact	Water Impact	Solid Waste Impact	Energy Impact	Economic Impact
Proposed Standards	+4**	-1**	-3**	-3**	-3**
Final Standards: Wet Control Systems Only	+4**	-1**	-3**	-2**	-3**
Final Standards: Wet + Dry Control Systems	+4**	-1**	-2**	-2**	-2**
No Revision to Current Standards	+3**	-1**	-1**	-1**	-2**

KEY

+	Beneficial Impact
-	Adverse Impact
0	No Impact
1	Negligible Impact
2	Small Impact
3	Moderate Impact
4	Large Impact
*	Short-Term Impact
**	Long-Term Impact
***	Irreversible Impact